Techno-Economic Analysis of Water Management Options for Unconventional Natural Gas Developments in the Marcellus Shale

by

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Abstract

The emergence of large-scale hydrocarbon production from shale reservoirs has revolutionized the oil and gas sector, and hydraulic fracturing has been the key enabler of this advancement. As a result, the need for water treatment has increased significantly and became a major cost driver for producers. What to do with the flowback water in light of scarce disposal facilities and substantial handling costs is a major impediment to the development of the natural gas resource, particularly in the Marcellus shale.

This thesis explores the technical, economic and regulatory issues associated with water treatment in the shale plays and identifies best practice water management pathways based upon the Marcellus shale characteristics. The key factors that affect the choice of water treatment options and infrastructure investments are identified and investigated in detail. These include, among others, proximity to disposal facilities, transportation costs, potential for wastewater reuse and make-up water requirements. The study is supplemented by an analysis of the flowback water geochemistry and an examination of the chemical components, like barium and strontium hardness ions, that can restrict the potential of flowback water reuse.

Important insights that will help inform the policy debate on how to best address both the environmental and operational water issues associated with hydraulic fracturing in the Marcellus region are derived through this study. Better reporting and monitoring of wastewater volumes is one of the main recommendations of this thesis. A wastewater management and reporting system that focuses on the optimization of water reuse among producers and facilitates information sharing could offer significant efficiencies in terms of reducing costs and minimizing negative environmental impacts. Furthermore, desalination technologies are currently cost prohibitive especially for onsite use. A governmental effort to identify and promote the development of desalination technologies that can effectively remove salts without being prohibitively expensive could help develop a sustainable water management solution.

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List of Acronyms

BBL – Barrels
BPD – Barrels per day
BPT – Best Practicable Control Technologies
BTEX – Benzene, toluene, ethyl benzene and xylene
CAPEX – Capital Expenditure
CBM – Coal Bed Methane
CERCLA – Comprehensive Environmental Response Compensation and Liability Act
CWA – Clean Water Act
CWT – Centralized Wastewater Treatment
DCA – Decline Curve Analysis
DOE – Department of Energy
DOFP – Date of first production
DOI – Department of Interior
EDR – Electrodialysis Reversal
ELG – Effluent Limitation Guidelines
EPA – Environmental Protection Agency
EPCRA – Emergency Planning and Community Right to Know Act
EUR – Estimated Ultimate Recovery
FO – Forward Osmosis
FOG – Free Oil and Grease
GAMS – General Algebraic Modeling System
GE – General Electric
GWPC – Ground Water Protection Council
HPDI – Historical Production Database Integration
IOGCC – Interstate Oil and Gas Compact Commission
IP – Initial Production
MCFD – Million cubic feet per day
MED – Multi-effect Distillation
MGD – Million gallons per day
MILP – Mixed Integer Linear Programming
MIT – Massachusetts Institute of Technology
MITEI – Massachusetts Institute of Technology Energy Initiative
MSDS – Material Safety Data Sheet
MSF – Multi-stage Flash Distillation
MVC – Mechanical Vapor Compression
MVR – Mechanical Vapor Recompression
NE – Northeast

NORM – Naturally Occurring Radioactive Material
NPDES – National Pollutant Discharge Elimination System
OH – Ohio State
OPEX – Operational Expenditure
ORC – Ohio Revised Code
PA – Pennsylvania State
PA DEP – Pennsylvania Department of Environmental Protection
PGC – Potential Gas Committee
POTW – Publicly Owned Treatment Works
PPM – Parts per million
RCRA – Resources Conservation and Recovery Act
RO – Reverse Osmosis
SDWA – Safe Drinking Water Act
SW – Southwest
TC – Type Curve
TCF – Trillion Cubic Feet
TDS – Total Dissolved Solids
TOC – Total Organic Carbon
TRI – Toxic Release Inventory
TSS – Total Suspended Solids
UIC – Underground Injection Control
USDW – Underground sources of drinking water
USGS – United States Geological Survey
UV - Ultraviolet
VCD – Vapor Compression Distillation
VOC – Volatile Organic Compound
WPR – Wells per rig
WV – West Virginia State
WV DEP – West Virginia Department of Environmental Protection
ZLD – Zero Liquid Discharge

1. Chapter 1 - Introduction

1.1. Introduction

The structure of the natural gas and oil industry in North America has changed dramatically over the past 5 to 6 years, with the emergence of large-scale production from unconventional resources, particularly shale rock deposits. Unconventional shale reservoirs are characterized by low permeability and require new procedures to stimulate economic levels of hydrocarbon production. Hydraulic fracturing has been a central enabler of this new paradigm. Hydraulic fracturing involves the high-pressure injection of water, sand and chemicals into wells in order to create fractures and increase the permeability of the rock to stimulate the flow of hydrocarbons. It requires approximately 4-6 million gallons of water to fracture each well. Anywhere from 10%-40% of this water flows back to the surface as highly contaminated water (DOE & ALL Consulting, 2009). This wastewater contains variable concentrations of salts, suspended solids, metals and naturally occurring radioactive material that render the water unfit for agricultural and human use. The volume of water needed for hydraulic fracturing coupled with the flowback water composition has led to wastewater management methods being heavily regulated by federal and state regulations. In emerging plays in the northeast like the Marcellus shale, water sourcing and flowback disposal present major operational and economic challenges for the oil and gas operators. Cheaper wastewater disposal methods, like injection of water inside disposal wells, are not widely available in the Marcellus shale resulting in the need to develop alternative cost effective water management methods and new, advanced water treatment options.

Effectively dealing with the water-related environmental, economic and operational challenges associated with hydraulic fracturing demands the implementation of integrated water management practices. This thesis explores the scale of hydraulic fracturing-related water treatment issues in the major U.S. unconventional oil and gas plays, and aims to identify best practice water management pathways based upon the Marcellus shale characteristics. A techno-economic study is performed on the various water management options available ranging from simple injection disposal to advanced centralized and on-site treatment and reuse options. Scenario analysis is performed in order to identify how events like changing drilling patterns, changing regulatory regimes and uncertain water treatment volumes affect the choice of water management options. Furthermore, a water management decision model is developed using linear programming optimization techniques to explore how regulatory changes can affect the water management system over time.

This work yields important insights that will help inform the policy debate on how best to address both the environmental and operational water issues associated with hydraulic fracturing in the Marcellus shale.

1.2. Hydraulic Fracturing: Technical, Environmental and Economic concerns

Hydraulic fracturing has proved to be the key enabler to unlocking vast shale gas and oil resources across North America, and increasingly in other regions of the world. Advanced hydraulic fracturing techniques enable production from low permeability shale rock that was not previously considered economic. Shale reservoirs have a very narrow vertical profile therefore horizontal drilling is performed to increase the wellbore surface area that is in contact with the formation. The fracturing process entails pumping large amounts of fracture fluids, primarily water with sand proppant and chemical additives at sufficiently high pressure to overcome the compressive stresses within the shale formation for the duration of the fracturing procedure. The process is exerted in stages, during which small parts of the wellbore are fractured sequentially. The process increases formation pressure above the critical fracture pressure, creating narrow fractures in the shale formation. The sand proppant is then pumped into these fractures to maintain a permeable pathway for fluid flow after the fracture fluid is withdrawn and the operation is completed (MITEI, 2011). Figure 1, illustrates the main features of a shale gas well. Anywhere from 10-40% of the water used to fracture the well flows back to the surface either as flowback or produced water. Flowback water is the water that flows to the surface during the well completion stage. Produced water is the water that flows to the surface when the well is considered to be under production.

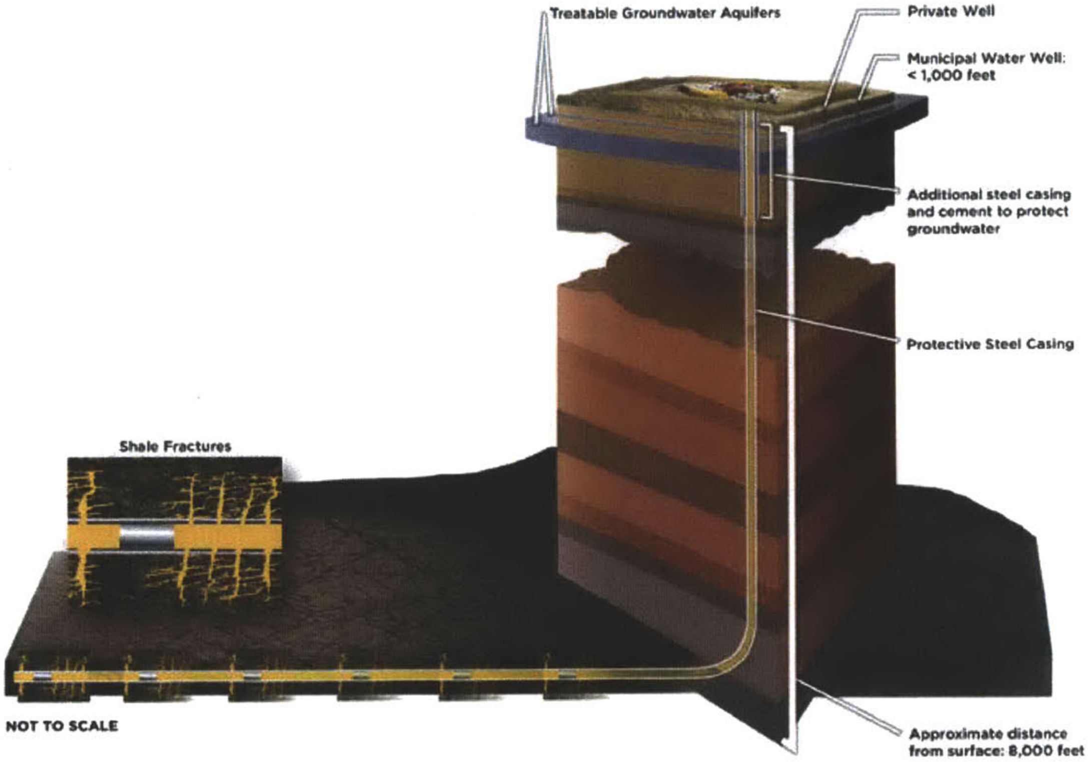

Figure 1 – Schematic illustrating the hydraulic fracturing process (Chesapeake, 2012)

Hydraulic fracturing, as a process of extracting oil, was first used in 1947 (Halliburton, 2012). Since then its use has increased dramatically and in recent years hydraulic fracturing has been tailored for use in shale gas and oil reservoirs.

There are some distinct differences between today's hydraulic fracturing operations and operations carried out earlier in the century that make this a timely and critical issue. Hydraulic fracturing used to be performed in vertical, shallower wells, using much less water per well and fewer fracturing stages, compared to the horizontal wells with long lateral lengths and multiple fracturing stages that are drilled today. As a consequence the average amount of fluid being used per well has been increasing. Historically, fracturing operations typically used 20,000 to 80,000 gallons of fluid to stimulate a single well (NYS, 1992). Today, hydraulic fracturing jobs in the Marcellus use anywhere from 2 to 7.8 million gallons of fluid (NYS, 2009), the exact amount depending on the length of the wellbore and the number of stages used. Overall, today's fracturing operations require more water, use more chemicals and generate more flowback and produced water. As a result concerns exist with regards to possible contamination of groundwater supplies, surface spills, scarcity of water supply and wastewater management.

Several studies have looked at the issue of groundwater contamination and determined that, assuming best well completion practices are followed, the risk of such contamination is very low (NYS, 2009; SEAB, 2011; Groat & Grimshaw, 2012). Fisher (2010), published a report showing that the highest growth of fractures in the Marcellus shale is thousands of feet below the ground water supply (see Figure 2). This reinforces the assumption that well casing issues at the upper end of the vertical wellbore and issues with leakages due to poor well completions appear to be the most common causes of reported contamination incidents. A recent draft study from the Environmental Protection Agency (EPA) suggested that ground water in Pavillion, Wyoming was tainted with compounds likely associated with gas and oil activity in the area, including hydraulic fracturing (EPA, 2011a). The constituents detected by the EPA were found in deep-water monitoring wells – not shallower drinking wells and the report was met with doubt. The EPA agreed to re-test its findings based on inconclusive data three months after the study was published (Reuters, 2012).

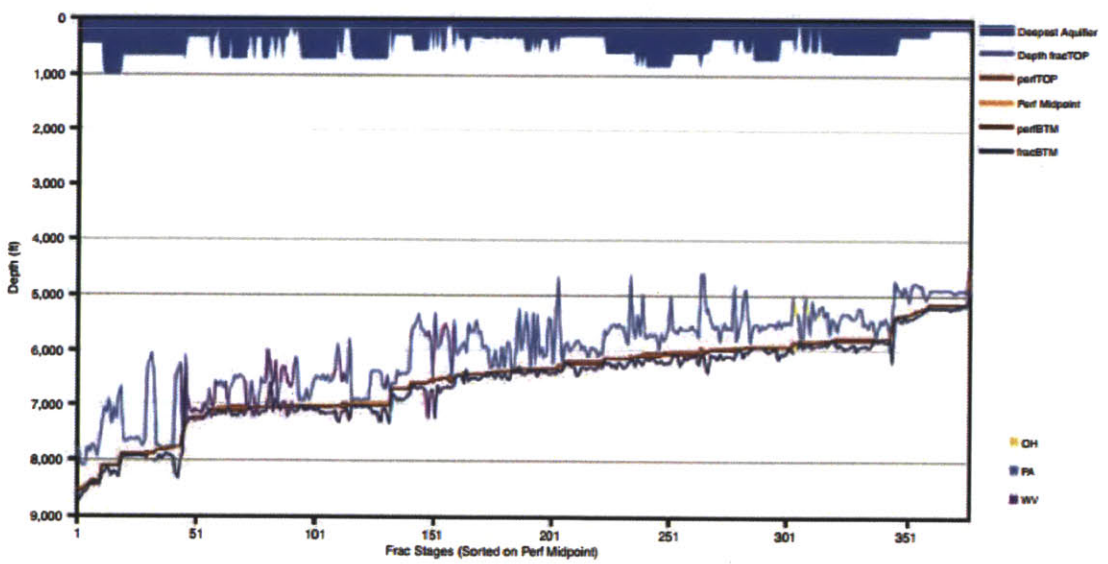

Figure 2 – Fracture Growth in the Marcellus shale (Total Vertical Depth); (Fisher, 2010)

One of the main reasons hydraulic fracturing operations have faced public opposition and increasingly strict regulation is because the recent shale discoveries lie in densely populated areas that have been unaccustomed to oil and gas operations. Figure 3 shows the location of the shale plays in North America.

Figure 3 – Current shale plays in North America (EIA, 2011)

Traditionally, oil and gas operations were concentrated in the southwest. With the discovery of the Marcellus shale (see Figure 3) operations have spread to the northeast. The lack of infrastructure to deal with environmental side effects such as high truck traffic on local roads, noise, associated pollution and large volumes of wastewater storage on-site, is causing major concerns among communities. For example, to transfer all the water needed to fracture a single horizontal well would take more than 1000 roundtrip truck-trips[1]. This excludes the trips needed to transfer equipment, materials and employees to the site, as well as the trips necessary to remove flowback, produced water and other wastes such as drill cuttings. Such excessive road usage can lead to increased pollution and noise levels and increased number of road accidents.

[1] Assumes a conventional water tank of 5,460 gallons capacity and an average water volume of 5.6 million gallons per fracturing job

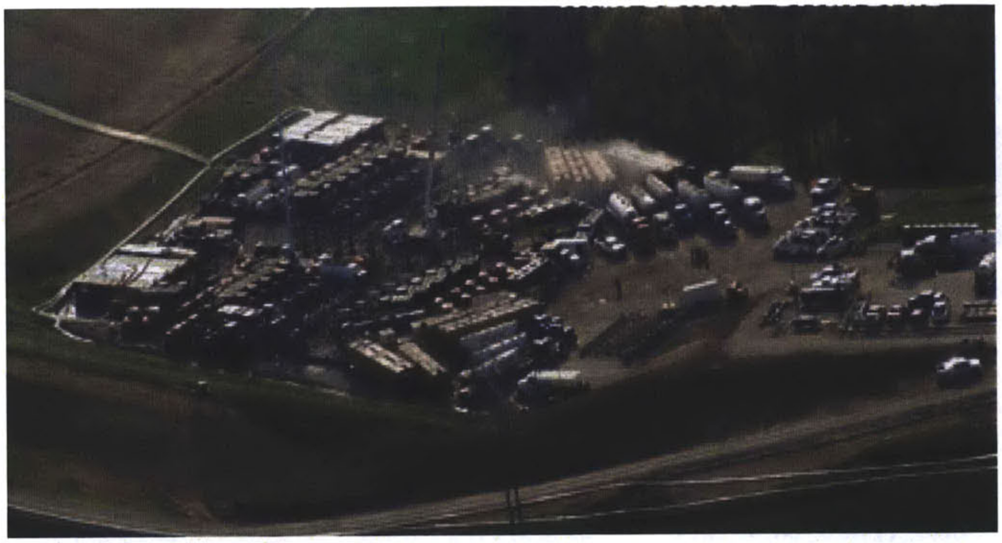

Figure 4 – Well Site Operations require more than 1000 roundtrip truck-trips to transfer the required water, chemicals and sand. More than 200 roundtrips are further required to transport wastewater to disposal facilities if no onsite wastewater management methods are employed. (Marcellus Shale, 2012)

This thesis concentrates on evaluating the wastewater management methods for produced and flowback water from the Marcellus shale. In this region, anywhere from 10%-20% of injected fluids can return to the surface after fracturing. This is lower than the flowback and produced water expected in other shale plays. The composition of this flowback water varies considerably, both by region and over time. Flowback water contains a range of constituents including dissolved solids, suspended solids, metals and in some instances naturally occurring radioactive material. As a result, flowback water requires careful handling, treatment and disposal in order to prevent any negative environmental impacts. In some regions, particularly in the southwest, operators have been able to dispose of flowback water by the traditional approach of injection into disposal wells[2]. However, the option to inject is not widely available in other shale plays, notably the Marcellus shale, due to the geology of the region as well as regulatory constraints. As a result other treatment and disposal options must be used in the Marcellus shale region. As production ramped up during 2008-2009 significant volumes of flowback water were disposed of at publicly owned treatment works (POTW) and direct discharging Centralized Wastewater Treatment (CWT) facilities. In April 2011, the Pennsylvania Department of Environmental Protection (PA DEP) passed regulations establishing effluent standards for treatment of flowback water and raised concerns that POTWs do not treat the water sufficiently prior to discharge. The oil and gas industry voluntarily ceased shipping flowback water to POTWs in May 2011. As a result, there has been a shortage of disposal

[2] Class II Underground Injection Control (UIC) wells regulated by the EPA

capacity in the region leading to very high disposal costs. Anecdotal evidence suggest water treatment and disposal costs of between \$5-\$10/bbl, with some instances of significantly higher costs. The majority of this cost is primarily due to trucking costs and the fact that disposal or treatment facilities are located far away from the well sites. Currently, many Marcellus producers are reusing flowback water for fracturing of subsequent wells; however this solution is only sustainable while drilling activity remains high and geographically concentrated.

1.3. Motivation and Thesis Overview

Many commercial entities are currently engaged in, or exploring the potential of providing flowback water treatment services in the Marcellus shale. A number of these have or are expected to construct centralized treatment facilities. Others are looking to offer mobile treatment units. Traditional wastewater treatment methods fail in many instances to effectively address the high salinity of flowback water. Thermal treatment technologies do offer a path to effective treatment of high salinity flowback; however, they are energy intensive and thus expensive. Operators and service companies have approached the problem by separating, filtering, and even distilling produced and flowback waters onsite for future reuse. Currently, it is unclear which approach provides the most appropriate platform for flowback water treatment. What to do with the flowback water in the light of scarce disposal facilities and substantial handling costs is a major impediment to the economic development of the Marcellus natural gas resource.

This thesis provides a framework for evaluating water management options for hydraulic fracturing wastewater and is using the Marcellus shale as a case study. This framework provides guidelines for assessing the viability of water management options. The cost of water treatment technologies applicable to the Marcellus shale are estimated based on industry data and the technical limitations of these technologies are evaluated. A techno-economic study is performed on the various water management options available ranging from simple injection disposal to advanced centralized and onsite treatment and reuse options.

The main objectives of the thesis are to identify what are the key factors that affect the choice of water management options in the Marcellus shale and to investigate how technological, industrial and regulatory changes affect decision making regarding water treatment technology options and infrastructure investments.

To this end, the thesis proceeds as follows. Chapter 2 provides an overview of the developments in shale gas production in North America and how regulation governs the shale gas operations. Chapter 3 proceeds to quantify the water treatment need in the Marcellus shale and examine all the available water management options. Chapter 4 includes an analysis of the flowback composition. The constituents of contaminated water are examined and the elements that are likely to be problematic during reuse are identified. Subsequently in Chapter 5, a framework for technology selection is developed based on the composition of flowback water and the required water treatment level. Chapter 6 includes a techno-economic analysis on six wastewater management options. The options are evaluated based on costs and technical limitations. Scenario analysis helps identify the variables that have the greatest effect on the selection of wastewater management options. Lastly, a water management decision model is developed using linear programming optimization techniques. The model allows us to investigate the selection of different water management options over time. An analysis is carried out on how foresight about future regulatory changes can affect current decisions about the water management system. To conclude Chapter 7, incorporates a discussion of the main results in the context of the existing operations in the Marcellus shale, and the extent to which current findings can be used to suggest policy changes that will help support the development of the water treatment infrastructure in the Marcellus shale region. Ultimately the goal is to enable the sustainable and safe development of the region's shale gas and oil resources.

2. Chapter 2 – The Natural Gas Industry; Shale Gas Developments, Water Controversies and Regulation

2.1. Shale Gas Production in North America

Natural gas, and to an even greater extent oil, have traditionally been produced from reservoirs which have high permeability, i.e. rock through which liquids can flow with ease. However, the availability of such reservoirs has been reduced due to cumulative production, particularly over the past 20-30 years. This has meant that operators have had to turn to producing from lower permeability, unconventional reservoirs. The main enabling technologies, that made this resource economically recoverable, are horizontal drilling and multi-stage hydraulic fracturing. Together, these techniques have unlocked enormous unconventional resources, particularly in shale rock deposits.

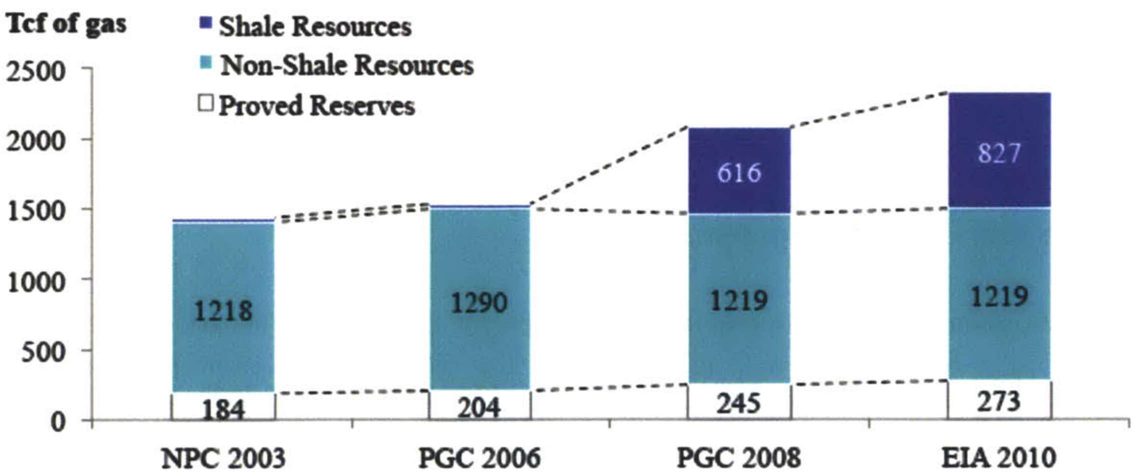

Figure 5 – Illustration of the recent dramatic growth in United States gas resource estimates due to the development of shale gas (MITEI, 2011)

Figure 5 illustrates how the development of these technologies over the past 5-6 years has resulted in between 600 and 850 trillion cubic feet (tcf) of natural gas being added to estimates of the total U.S. gas resource base (PGC, 2008) (PGC, 2010), (EIA, 2011). Given that total U.S. annual gas consumption is ~24 tcf, this new volume represents up to 35 years of additional gas. Figure 6 shows the expected increase in natural gas production in the US up to 2035. Shale gas production is expected to rise to 49% of the natural gas production compared to 23% in 2010 (EIA, 2012). These projections are likely to be dampened by the current low natural gas price (Bloomberg, 2012), however a significant increase in production is expected to take place.

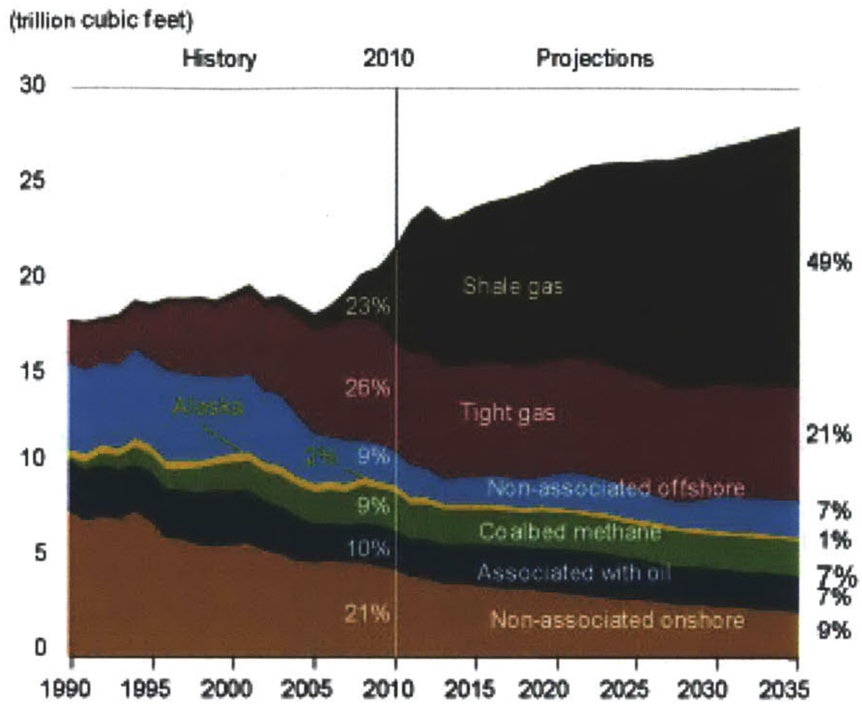

Figure 6 – United States natural gas production projections (EIA, 2012)

2.2. Shale Gas Developments per Play

Projections on how production from each shale play will develop are not widely available in industry reports. In order to investigate the different production patterns and wastewater flows from different geographic regions we need to calculate potential future production rates per play (i.e. Barnett, Marcellus, Haynesville, Fayetteville, Woodford, Eagle Ford, etc.). The map in Figure 3 shows the location of the different plays and some of their distinct characteristics. Initial production rates, production profiles and flowback wastewater volumes vary significantly for each geographic location.

Projections for natural gas production were made using an illustrative pro-forma model and type curve analysis. This analysis is an expansion of the 2009 projections carried out by the MIT Energy Initiative – The Future of Natural Gas Study (2011). The production rates for each individual play were evaluated based on a type curve analysis and then combined together to identify the total projected production from the five main U.S. shale plays (see Appendix A for details).

Natural Gas Production Projections

The Natural Gas Production model developed for The Future of Natural Gas study (MITEI, 2011) was updated and expanded to analyze the current projections of natural gas production based on the updated type curves (see Appendix A).

The following variables were used as inputs to an illustrative pro-forma model (data values are shown in Table 1):

- Undiscovered recoverable reserves by shale basin (PGC, 2008)
- Well count by shale basin (HPDI, 2011)
- Rig count (Updated to 2011Q1) (RigData, 2011)
- Wells per rig (WPR) per year (HPDI, 2011; RigData, 2011)
- Well cost (INTEK, 2010)

	Barnett	**Marcellus**	**Fayetteville**	**Haynesville**	**Woodford**
Recoverable resources (TCF)	75	84[3]	32	75	22
Well count (2011)	12,179	1,491	3,269	1,255	1,321
Well cost ($M)	1.6-3.7	3.0-4.7	1.8-3.0	6.0-10.0	4.6-8.0
Rig count (2011Q1)	73	134	30	149[4]	20
Wells per rig per year (2009Q4-2011Q1)	21	7.5[5]	27	3[6]	13

Table 1 – Model inputs used for the Natural Gas Production model

The updated Natural Gas Production model illustrates a view of how different plays might develop up to 2030. Figure 7 illustrates the main differences between the original model from 2010 and the updated model. The main observation is with regards to the Haynesville play. Large developments in the area occurred in 2011 and the rig count increased dramatically from 50 rigs at the end of 2009 to 149 rigs at the beginning of

[3] Value updated by US Geological Survey (USGS, 2011)
[4] Haynesville rig count is high compared to values used in the previous Natural Gas Production model (149 rigs in 2011Q1 compared to 50 rigs in 2009Q4). This causes a large increase in gas production from Haynesville compared to Marcellus production.
[5] Various companies report in the range of 8-12 wells per rig
[6] This value seems low however it is not unlikely due to the different geology in the Haynesville shale, which requires more time and higher cost per drilling of a new well. Companies report performance of 1-2 rigs for every 7-9 wells.

2011. This, coupled with the very high production rates for the Haynesville shale, increased the projection of shale gas production from that area in the next few years. The model is constrained so that the number of new wells drilled per month remains constant based on current rig count and rig performance (wells per rig). We expect rig count and performance to vary over the years, which is why we expect the Haynesville production to be less than what is projected in the model.

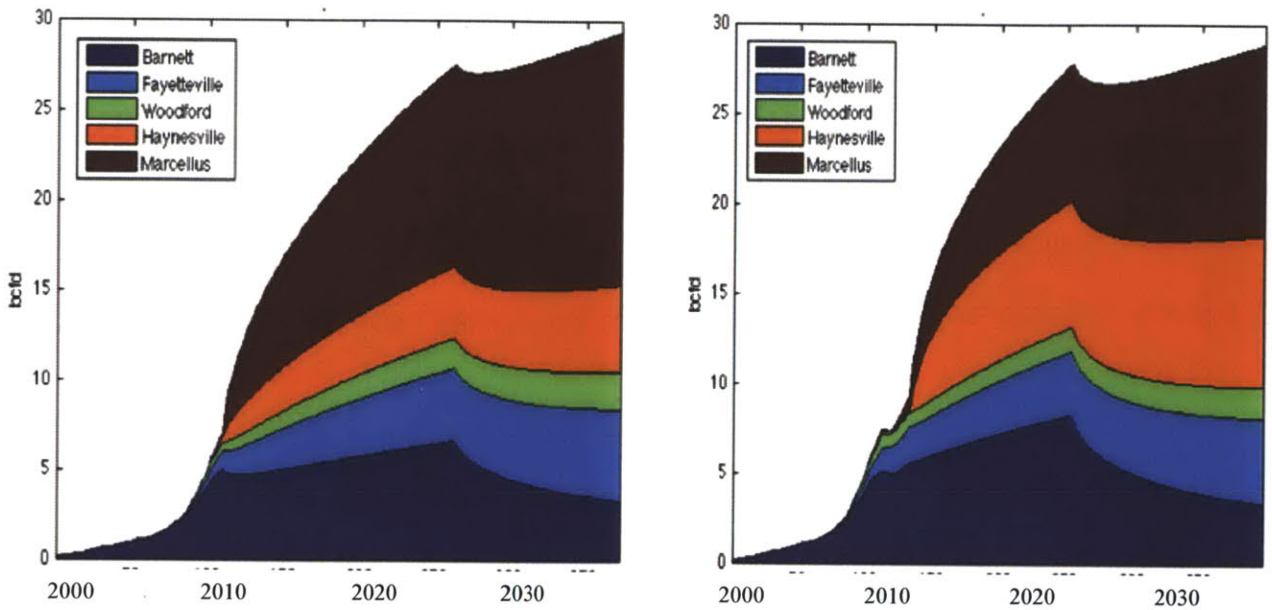

Figure 7 – Illustrative pro-forma model - Potential Production Rate that could be delivered by the major US Shale Plays up to 2030. Left: Production analysis shown in MIT Future of Natural Gas Study (MITEI, 2011) given 2009 drilling rates and mean resources estimates. Right: Updated production analysis based on 2011 drilling rates, well count and mean resource estimates.

The Haynesville and the Marcellus are the two fastest producing shale plays. Flowback and produced water volumes are linked to production since (a) more drilling means more hydraulic fracturing and thus more flowback and (b) produced water flow rate increases as production rate increases. Based on Figure 7, production rates for the Marcellus will continue to increase for the next ~25 years. This indicates that the water management issue will become more pressing over the years and it is important to develop a robust solution that can handle increasing volumes of wastewater.

2.3. Controversies Surrounding Water Issues

Increased production rates in the Marcellus shale means that the water demand for hydraulic fracturing operations will also increase. Water usage by the oil and gas industry has been the subject of controversy both because it can lead to scarcity of supply and contamination of groundwater supplies.

2.3.1. Hydraulic Fracturing Fluid – Fresh Water Volumes

Hydraulic fracturing of a well involves, on average, 12 fracturing stages, with each stage using about 10,000-12,000 bbl of water. According to a November 2010 market study by Cap Resources, water usage in the main US shale plays is projected to increase from about 450 million bbl in 2010 to about 675 million bbl by the end of 2015 (Kidder et al., 2011). This is equivalent to a water demand of 52 million gallons[7] per day (MGD) in 2010 and 78 MGD in 2015 for all the shale plays. Gaudlip et al. (2008) projects that in the Appalachian region approximately 8.4 MGD will be needed for hydraulic fracturing before a plateau is reached and water usage begins to decline. Even though the size of the volumes is large, the current hydraulic fracturing related water demand should be put in perspective according to the water usage from other industries in the energy sector. For example, on a per mmbtu basis the shale gas industry uses less water than conventional oil and natural gas extraction (Chesapeake, 2009). Estimated average water usage volumes from both drilling and hydraulic fracturing operations are shown in Table 2.

	Average Fresh Water Volume used for drilling [M gals]	Average Fresh Water Volume used for hydraulic fracturing [M gals]
Barnett	0.3	4.6
Eagle Ford	0.1	5.0
Haynesville	0.6	5.0
Marcellus	0.1	5.6

Table 2 – Average volumes of water used per shale well for drilling and fracturing (King, 2012; DOE & ALL Consulting, 2009; EPA, 2011b; Chesapeake, 2010; SRBC, 2010). Refer to Appendix C for reference and data collection of water usage volumes.

Marcellus Shale water usage

[7] 1 barrel (bbl) is equivalent to 42 U.S. gallons of water

Year	PA DEP Marcellus Shale Permits Issued	PA DEP Marcellus Shale Wells drilled	WV DEP Marcellus Shale Permits Issued	WV DEP Marcellus Shale Wells drilled
2008	519	196	400	274
2009	1984	763	424	47
2010	3314	1454	244	2
2011	3512	1937	n/a	n/a

Table 3 – Total number of permits issued and wells drilled in the Marcellus shale[8] (PA DEP, 2012; WV DEP, 2012; Veil, 2012b)

Assuming a hypothetical maximum of wells drilled is one and a half times the wells drilled in 2011 results in a maximum of no more than 3,000 wells drilled per year. Assuming that an average 5.7 million gallons of water are necessary per well for hydraulic fracturing (Table 2) leads to 16.6 billion gallons of water per year required for the Marcellus shale. This is equivalent to 45.5 MGD which is 4 times higher than the Gaudlip et al. (2008) prediction in 2008, illustrating how rapid the developments in the Marcellus shale have been over the past few years. The actual combined water withdrawals in New York, Pennsylvania and West Virginia in 2005 were 24,577 MGD (Kenny et al., 2009). These withdrawals include public water supply, domestic water supply, irrigation, livestock, industrial use, thermoelectric use etc. Comparing the hypothetical maximum water used of 45.5MGD to the actual combined water withdrawals in 2005 means that less than 0.2% of water withdrawals in the Marcellus shale region will be used for hydraulic fracturing.

The above projection should be treated with caution. Estimates of maximum wells drilled could significantly overestimate or underestimate the actual water quantity. Also technological advancements to drill longer horizontal wells may increase the volume of water necessary for fracturing. Lastly, operators are already exploring and utilizing options of recycling and reusing wastewater. This can significantly decrease the amount of water necessary for hydraulic fracturing operations.

[8] New York wells were not considered in this analysis since they constitute a very small percentage of drilling activity in the Marcellus shale and reliable reporting data is not available

2.3.2. Hydraulic Fracturing Fluid – Chemical Additives

Hydraulic fracturing fluid includes chemical additives (approximately 2% of the fracturing fluid by volume (FracFocus, 2012)) to facilitate the fracturing process downhole. These chemicals have been the subject of concern and scrutiny by various concerned organizations. As a result some oil and gas operators currently voluntary disclose the composition of the fracturing fluid. Some of the most common additives used in fracturing water are shown in Table 4.

Most Common Fracturing Additives	**Composition**	**Use**	**% of shale fractures that use this additive**	**Alternative use**
Friction Reducer	Polyacrylamide	Reduce downhole friction	100%	Adsorbent in baby diapers, flocculent in drinking water preparation
Biocide	Glutaraldehyde	Reduce or eliminate bacteria	80%	Medical disinfectant
Alternate Biocide[9]	Ozone, Chlorine dioxide, UV	Reduce or eliminate bacteria	20%	Disinfectant in municipal water supplies
Scale Inhibitor	Phosphonate & polymers	Prevents scale formation	10-25%	Detergents and medical treatment for bone problems
Surfactant	Various	Increases viscosity of fracturing fluid	10-25%	Dish soaps, cleaners
Acid	Hydrochloric acid	Dissolves minerals and initiates cracks in the rock	n/a	Swimming pool chemicals and cleaners

Table 4 – Common Additives Used in Hydraulic Fracturing (King, 2012)

The industry has become more transparent, releasing publicly information about the chemicals used in fracturing fluid with the FracFocus.org organization being the leading entity heading this effort. However, there is still concern about the quality of reporting.

[9] Alternative biocides are becoming more common and are replacing conventional biocides

2.4. Regulation

The current status of regulatory activity for shale gas operations revolves around environmental concerns in an attempt to regulate waste management and waste disposal methods. The major federal laws governing waste materials and management activities include the Resources Conservation and Recovery Act (RCRA), the Clean Water Act (CWA) and the Safe Drinking Water Act (SDWA).

Law	Material Subject to Regulation	Activity Subject to Regulation
CWA	Aqueous waste streams	Surface discharge
RCRA	Solid and hazardous wastes (unless excluded or exempted)	Generation, transportation and treatment; storage and disposal
SDWA	Waste fluids or slurries	Underground Injection

Water and waste management in connection with oil and gas activities involves discharge and injection operations. The main laws governing these activities include the CWA and the SDWA. The EPA may authorize willing and able states to take the lead responsibility for the day-to-day program implementation and enforcement. Otherwise, the EPA runs the programs in direct implementation.

2.4.1. History of Hydraulic Fracturing

Disputes around the federal and state regulation governing hydraulic fracturing operations have been ongoing for more than 30 years. The timeline below identifies the main regulatory and policy events that govern the operations of the oil and gas industry, and specifically regulate hydraulic fracturing operations (Energy In Depth, 2012; PA DEP, 2010; EPA, 2011a).

1948 First commercially employed well receives hydraulic fracturing treatment (Grant County, Kan)

1972 Under the Federal Water Pollution Control Amendments of 1972, the National Pollutant Discharge Elimination System (NPDES) was introduced, which is a permit system for regulating point sources of pollution such as oil and gas extraction operations.

1974 Safe Drinking Water Act (SDWA) enacted – SDWA protects public water supplies (groundwater) and creates new programs and regulations to protect underground sources of drinking water (USDW). Hydraulic fracturing was not considered for regulation under SDWA.

1977 The Clean Water Act (CWA) was enacted based on the Federal Water Pollution Control Amendments of 1972. The CWA governs water pollution in all navigable waters in the United States but does not directly address groundwater, which is included in SDWA and RCRA.

1979 EPA imposed a zero-discharge requirement for all produced water resulting from onshore oil and gas production activities.

1980 Congress conditionally exempted oil and gas wastes, including produced water, from the hazardous waste management requirements of RCRA.

1990s George Mitchell successfully combines horizontal drilling with hydraulic fracturing enabling what is now known as the shale gas revolution.

2002 EPA releases draft of hydraulic fracturing study, concluding that the technology does not pose a risk to drinking water but raises potential concerns about the use of diesel fuel.

2003 Major operators sign memorandum of agreement with EPA not to use diesel when conducting fracturing operations near USDWs.

2004 EPA releases its final report on the use of hydraulic fracturing in coal bed methane (CBM) operations concluding that no hazardous chemicals were found in fracturing fluids and that hydraulic fracturing does not create pathways for fluids to travel between rock formations to affect water supply.

2005 Energy Bill – House passes bipartisan bill clarifying that Congress never intended hydraulic fracturing to be regulated under SDWA.

2005 Range Resources drill the first wells in the Marcellus Shale in Pennsylvania.

2008 Outside interest groups expand efforts to attack hydraulic fracturing in mid-Atlantic region (Marcellus Shale).

2010 The state of Wyoming approves a rule to require disclosure of the additives used during hydraulic fracturing.

2011 Pennsylvania updates its regulations to include disclosure requirements for hydraulic fracturing fluids. Also more stringent effluent discharge limits come into effect based on the PA DEP Code on Chapter 95 Wastewater Treatment Requirements.

2011 The Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) officially launch FracFocus.org, an online disclosure website for the additives used in hydraulic fracturing.

2011 EPA issues a draft report on water quality in Pavillion, WY, which concludes that hydraulic fracturing was likely the cause of water contamination in the area. Numerous state officials and regulators criticized the report. EPA backtracked on its initial claims in February, 2012.

2.4.2. Resources Conservation and Recovery Act

The Resources Conservation and Recovery Act (RCRA) sets standards for the treatment, storage and disposal of hazardous waste in the United States. It sets national goals to protect the human health and the natural environmental from the potential hazards of waste disposal.

Exempt E&P Waste Streams	Nonexempt E&P Waste Streams
Caustics if used as drilling fluid additives Cement slurry returns and cement cuttings Debris, crude-oil soaked/crude-oil stained Drill cuttings/solids Drilling fluids/muds Drilling fluids and cuttings from offshore operations disposed of onshore Liquid hydrocarbons removed from the production stream Liquid and solid wastes generated by crude oil and tank bottom reclaimers Pit sludges and contaminated bottoms from storage or disposal of exempt wastes Produced sand Produced water Produced water constituents removed before disposal Soils, crude-oil contaminated Tank bottoms and basic sediment from storage facilities that hold product and exempt waste (including accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments) Volatile organic compounds from exempt wastes in reserve pits or impoundments or production equipment Well completion, treatment, and stimulation, and packaging fluids Workover wastes (blowdown, swabbing and bailing wastes)	Batteries (lead-acid and nickel-cadmium) Caustic or acid cleaners Cement slurries, unused Chemicals, surplus/unusable Compressor oil, filters, and blowdown waste Debris, lube oil (contaminated) Drilling fluids (unused) Drums/containers, containing chemicals/lubricating oil Drums, empty and rinsate Hydraulic fluids (used) Oil, equipment lubricating (used) Sandblast media Scrap metal Soil, chemical-contaminated, lube oil-contaminated, and mercury-contaminated Solvents, spent (including waste solvents) Thread protectors, pipe dope-contaminated Vacuum truck rinsate (from tanks containing nonexempt waste) Well completion, treatment and stimulation fluids (unused)

Table 5 – Examples of Exempt and Nonexempt Exploration & Production Waste Streams from Oil & Gas Operations (Veil & Puder, 2006)

In 1988, the EPA published its regulatory determination by exempting certain oil and gas wastes from the hazardous waste management requirements of Subtitle C of the RCRA. RCRA exemptions for oil and gas toxic materials mean that they can be injected into disposal wells with fewer regulatory controls. Table 5 presents the exempt and non-exempt oil and gas wastes. It is important to note that produced water is exempt from the RCRA management requirements, therefore it can be injected in disposal wells without treatment.

2.4.3. Clean Water Act

Flowback and produced water is subject to the Clean Water Act (CWA), which regulates the discharge of pollutants into U.S. waters. The current regulations require shale gas operators to obtain permits under the National Pollution Discharge Elimination System (NPDES), which is authorized under the Clean Water Act. Numerical effluent limits present the primary mechanism for controlling discharges of pollutants.

Under the CWA, the Environmental Protection Agency (EPA) has implemented pollution control programs such as setting wastewater standards for industry and water quality standards for all contaminants in surface waters. EPA's effluent limits describe the pollutants subject to monitoring in industry as well as the appropriate quantity or concentration of pollutants. The allowable best practicable control technologies (BPT) for flowback and produced water include underground injection and use of evaporative ponds. Stringency of BPTs is likely to increase by implementing effluent concentration-based discharge limits (limiting total dissolved solids (TDS) allowance) and technology-based control requirements (EPA, 2011b). More stringent regulatory standards on effluent pollutant concentrations will require the development of technologies with advanced water treatment capabilities. That requirement, coupled with the increased shale gas production and limiting injection wells in areas like the Marcellus shale, exemplify the urgency for improved wastewater management options.

CWA does not authorize onsite discharge of produced water to navigable waters in the United States. This imposes a zero-discharge requirement for all produced water from onshore wells (NETL, 2012). Marcellus shale wells are included under this zero-discharge requirement. Due to this being a federal regulation, treated wastewater cannot be discharged on-site even if it meets the effluent limitation guidelines (ELGs) imposed by EPA. As a consequence produced water, if not recycled and reused, needs to always be transferred away from the well site to be treated at a centralized treatment facility for discharge. In order to discharge water from an onshore well without sending it to industrial treatment units, semi-mobile treatment facilities located in a regional location can attempt to obtain an NPDES permit as a centralized facility. However, they need to be treating sufficient quantities of produced water to the required effluent limits and each time they relocate, they would need to obtain a new discharge permit (Veil, 2012a).

There are a few exemptions specific to the oil and gas sector with regards to NPDES permitting. Hydraulic fracturing fluids used in natural gas production are not considered pollutants subject to NPDES permitting. The exemption also covers produced water that is disposed of by re-injection into gas wells. Injection into an oil or gas well to facilitative production or produced water re-injected in deep injection wells for disposal, are not considered pollutants if approved by a state and that state determines that such injection or disposal will not result in the degradation of ground or surface water resources (33 U.S.C. §1362(2)(B)).

2.4.4. Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) gave the EPA the authority for underground injection control (UIC) regulation. Wells used for injecting oil field waste materials are considered Class II wells and are separated in disposal wells (Class II-D) and recovery wells (Class II-R). See Appendix B for details on the different types of disposal wells. States can receive primary responsibility (primacy) for the UIC program under Section 1422 of the SDWA. The EPA's regulations establish minimum standards for state programs prior to receiving primacy. If the states do not obtain primary responsibility for the UIC program the oversight is conducted by an EPA regional office. It is important to note that produced water re-injected for disposal in UIC disposal wells is not considered a pollutant and does not require treatment.

Currently the EPA has delegated primacy for all well classes to 33 states and 3 territories. The EPA shares responsibility with 7 states (i.e. the EPA has authority over some classes and the state has authority for others).

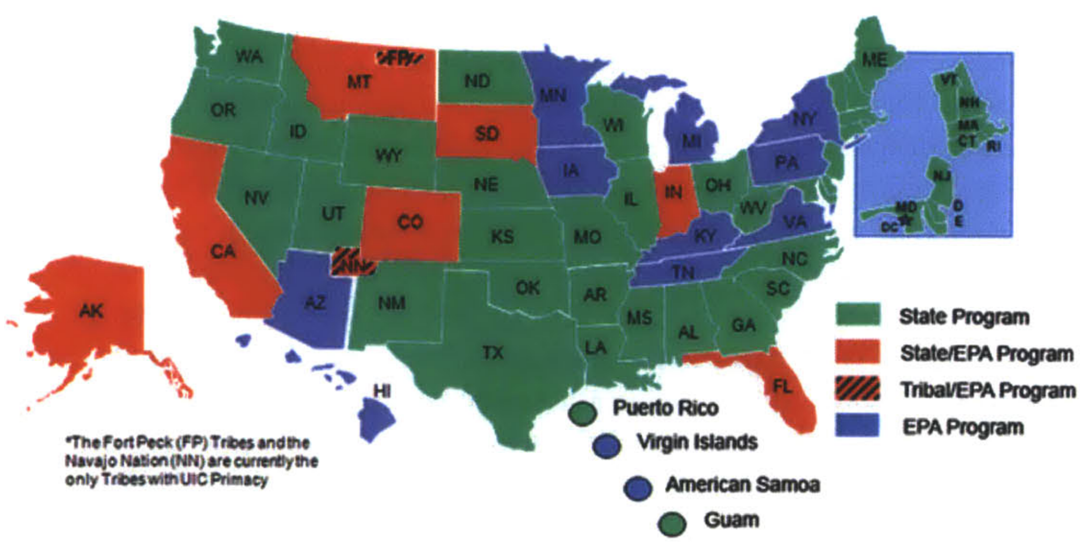

Figure 8 – Underground Injection Control (UIC) Program (EPA, 2011c)

Ohio has received Class II program primacy and thus regulates all operations regarding injection of produced water. Disposal of "brine or other wastes substances resulting, obtained or produced in connection with oil and gas drilling exploration or production" in Class II disposal wells is authorized by Section 1509.22 of the Ohio Revised Code (ORC). In contrast, the EPA regional offices are responsible for the operation of disposal wells in New York and Pennsylvania. Both those states are lacking injection capacity and waste from oil and gas operations is often trucked to Ohio.

2.4.5. Hydraulic Fracturing Fluid Disclosure

In 1986, Congress enacted the Emergency Planning and Community Right to Know Act (EPCRA). EPCRA established requirements for federal, state and local governments, tribes, and industry regarding emergency planning and "community right-to-know" reporting on hazardous and toxic chemicals. Under Sections 311 and 312 of EPCRA, facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDS), describing the properties and health effects of these chemicals, available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDS exist. Information about chemical inventories at facilities and MSDS must be available to the public. Any hazardous chemicals above the threshold stored at shale gas production and processing sites must be reported in this manner. These chemicals may be brought on site for a few days, at most, during fracturing or work-over operations. EPCRA Section 304 requires reporting of releases to the environment of products used in oil and gas production that exceed reporting thresholds.

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. To date, EPA has not included oil and gas extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI. While shale gas production facilities do not normally store the materials subject to EPCRA reporting, a limited number of chemicals used in the hydraulic fracturing process, such as hydrochloric acid, are classified as hazardous under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), which requires reporting of releases into the environment of these materials.

In addition to federal disclosure laws, some states like Wyoming, Pennsylvania and Arkansas have promulgated public disclosure rules related to hydraulic fracturing (Energy In Depth, 2012). Although the content of these rules differs, the intent of each is to provide the public with information about the chemicals being used to fracture wells. The industry has opened up, publicly releasing information about the chemicals used in fracturing fluid with the FracFocus.org organization being the leading entity heading this effort. A proposed rule by the U.S. Department of Interior was issued in May 2012 requiring producers to disclose the chemicals used in the fracturing fluids on public lands after drilling is completed (DOI, 2012).

2.4.6. Pennsylvania Department of Environmental Protection – Discharge Limits

In the Commonwealth of Pennsylvania, new regulatory limits have been proposed to limit water discharges to surface waters. The Pennsylvania Department of Environmental Protection (PA DEP) announced on April 15, 2009 that all industrial discharges would be facing stricter effluent limits. The PA DEP Code on Chapter 95 Wastewater Treatment Requirements was modified on August 1, 2010 and came into effect on January 1, 2011. PA DEP Code Section §95.10 on Wastewater Treatment Requirements can be found in Appendix D.

PA DEP Code on Chapter 95 Wastewater Treatment Requirements

Regulatory changes to handling high total dissolved solids (TDS) water were first prompted by the escalating TDS levels in Pennsylvania's rivers. These regulations apply to industries that generate high TDS wastewater, including the oil and gas drilling industry. The pre-existing practice for high TDS wastewaters involved treatment in Publicly Owned Treatment Works (POTW). These are municipal waste treatment facilities where heavy metals, solids and oils are removed. No treatment for TDS, sulfates or chlorides was taking place other than dilution. As documented by the rising levels of TDS, dilution could no longer be considered adequate treatment for high TDS wastewaters.

According to the Pennsylvania Code, Title 25, Environmental Protection, Chapter 95 Wastewater Treatment Requirements (PA DEP, 2010) the official effluent standards (daily maximums) for hydraulic fracturing wastewater as of January 1, 2011 are:

- 500 mg/L for TDS
- 250 mg/L for sulfates
- 250 mg/L for chlorides
- 10 mg/L for total barium
- 10 mg/L for total strontium

Existing publicly owned treatment works (POTW) and centralized waste treatment (CWT) plants authorized prior to August 21, 2010, are exempt from the treatment requirements stated above. Provided they are not located in areas with water quality problems, existing sources of high TDS wastewater and existing pretreatment facilities may continue to operate as they have been, until they propose to expand or increase their existing daily discharge load. From that point they will have two years to comply with the new requirements. Discharges from a POTW may not be authorized, unless treatment at a CWT meeting all the requirements precedes treatment by the POTW. Facilities of new or expanded treated discharges of wastewater resulting from fracturing, production, field exploration, drilling or well completion of natural gas wells must meet the above requirements in order to be authorized by the PA DEP.

3. Chapter 3 – Wastewater Volumes and Wastewater Management Options

3.1. Flowback and Produced Water Overview

When the flowback water returns to the surface it can contain dissolved salts, dissolved minerals, residual fracturing fluid additives, heavy metals, bacteria, suspended solids, naturally occurring radioactive material (NORM), volatile organics (VOCs), hydrocarbons, and ammonia.

Water can be classified by the amount of total dissolved solids (TDS) per liter. Fresh water has less 1500 mg/L TDS while saline water has between 15000 – 30000 mg/L TDS. On the other hand, seawater has 30000 – 40000 mg/L TDS and concentrated brine is considered as water with more than 40000 mg/L TDS (Wendell, 2007; King, 2011; WQA, 2011). Wastewater from hydraulic fracturing operations can have TDS concentration that is much higher than saline water; therefore treatment is essential before surface discharge or reuse.

Several methods are used to distinguish between flowback and produced water volumes. For the purposes of this thesis the operational definition will be used. Water produced during the well completion stage is defined as flowback. When the well is considered to be under production the water is referred to as produced. At that point all associated costs are operation costs. The changeover is expected to occur approximately 14 days after fracturing. Other studies use a different time frame to distinguish between flowback and produced water (e.g. 30 day cut-off). The time frame is not set and can vary depending on the operator or organization. In this specific study, 14-day cut-off will be used to distinguish between flowback and produced water.

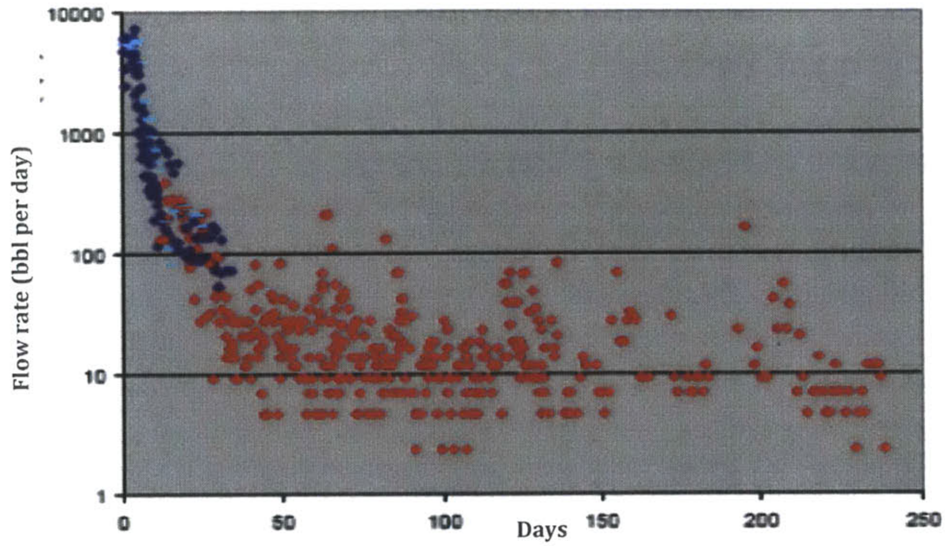

Figure 9 – Typical Flowback/Produced Water Vs Time curve. Blue represents the flowback water; Red represents the produced water (Gaudlip, 2010)

Volumetric flow rates during the flowback phase are significantly larger than during production as can be seen from Figure 9. In terms of composition, the produced water tends to have higher concentration of the various minerals than flowback water, likely because of a greater residence time downhole.

3.2. Flowback Water Volume Estimation

The water recovery ratio is the total volume of water that flows back to the surfaces as a percentage of the fracturing fluid injected during the hydraulic fracturing process. This includes both flowback and produced water. The recovery ratio tends to vary by shale formation. Recovery ratios in the Marcellus shale tend to be between 10% to 20% (Veil, 2012b; King, 2012). Figure 10, shows the recovery ratio over time for wells in the Marcellus shale. The particular set of wells in Figure 10 has a slightly higher than expected recovery ratio at the 14 day mark, which is between 19% - 29%. The recovery ratio at the 14-day point can give us a good indication of the amount of flowback water we can expect. There is no rigorous analytical method to predict flowback water volumes therefore estimates are made using historical data and correlating the recorded volumes to different geographic regions within shale plays.

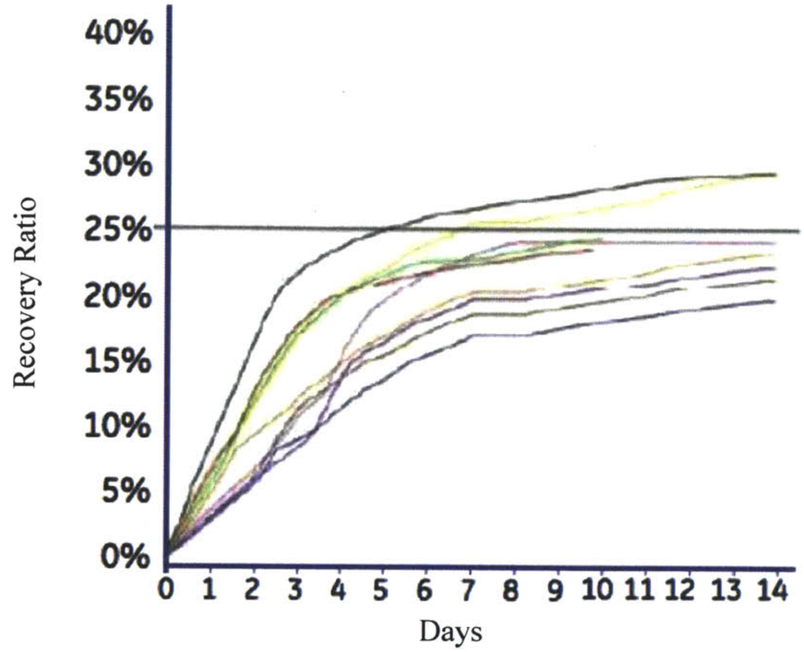

Figure 10 – Recovery ratio over time from wells in the Marcellus shale (Gaudlip, 2010)

3.3. Produced Water Volume Estimation

Produced water data is available through the HPDI database; however only data for the Barnett and Haynesville plays are reported. The possibility of a relationship between production rate and produced water is investigated in this section. "Type curve" (see Appendix A for background) were constructed for produced water flow by normalizing the produced water flows of all wells to a given starting date. The produced water flows were plotted against a natural gas production type curve for that particular starting date. The results are shown in Figure 11.

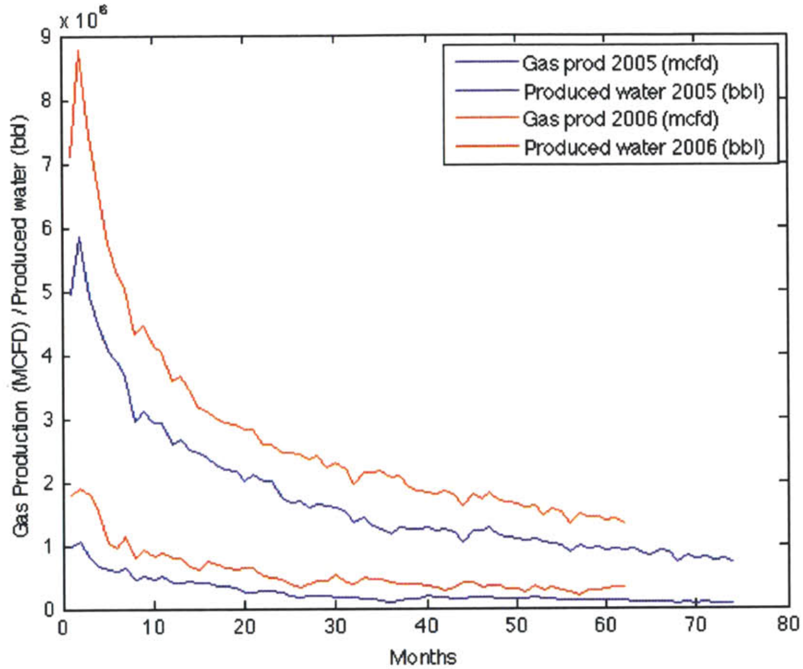

Figure 11 – Production Type Curves plotted against Produced Water "Type Curves" for the Barnett shale for wells starting production in June 2005 and June 2006.

One can observe a linear correlation between natural gas production and produced water. Table 6 shows the correlation coefficients for all the production years for both Barnett and Haynesville shale.

First production	**Correlation coefficient – Barnett Shale**	**Correlation coefficient – Haynesville Shale**
June 2005	0.892	n/a
June 2006	0.989	0.765
June 2007	0.960	0.996
June 2008	0.973	0.960
June 2009	0.680[10]	0.967
June 2010	0.971	0.999

Table 6 – Correlation coefficients between production rate (mcfd) and produced water (bbl)

[10] Low correlation coefficient due to inconsistent and sparse data for that year

The high correlation coefficients reinforce the argument for a linear relationship between natural gas production and produced water. A linear coefficient was calculated for every type curve and averaged across all the types curves to obtain a mean and standard deviation. Stochastic sampling was used to select a relationship coefficient from the derived distribution. A new relationship coefficient was used for every weekly data point. This calculation was combined with the Natural Gas Production Model (MITEI, 2011) to produce projections for produced water. The results are shown in Figure12.

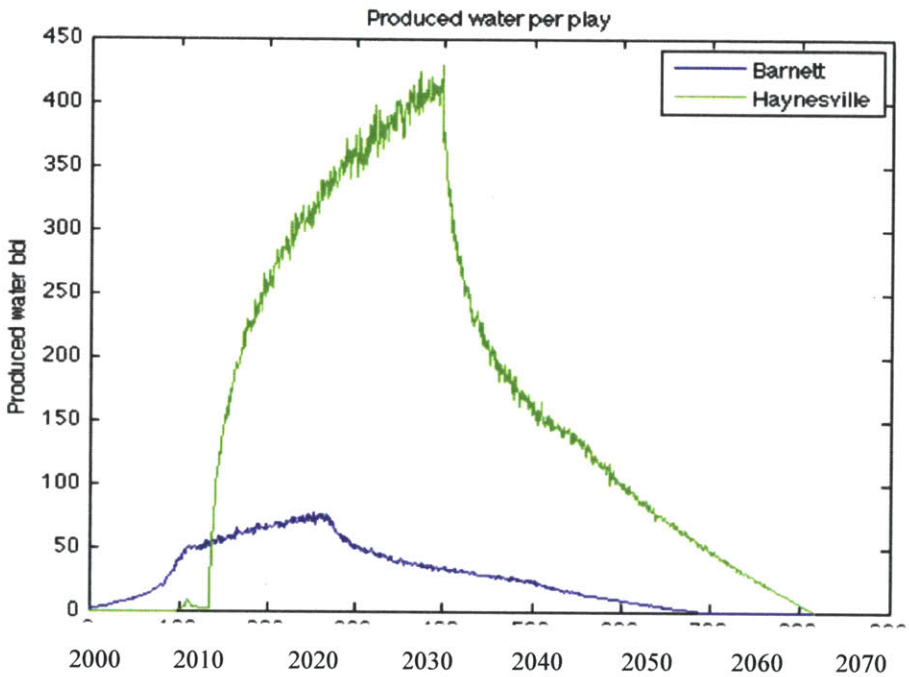

Figure 12 – Produced water projections from 2000 to depletion for the Barnett and Haynesville shale

Estimated cumulative produced water from an average well until well depletion:
Barnett: 57,992 bbl = 2.4 M gallons
Haynesville: 127,900 bbl = 5.3 M gallons

The above estimates should be used with caution. Based on the production relationship used, a play with larger gas production is most likely to produce higher volumes of produced water, however we know from the literature that certain fields like the Marcellus shale, has little produced water volumes despite being one of the largest producing plays.

3.4. Water Volume analysis in Marcellus, PA

The Pennsylvania Department of Environmental Protection (PA DEP, 2011a) has been releasing production and wastewater information for the Marcellus shale. The data collection process is a recent effort to provide more transparency to the controversial issue of produced and flowback water management.

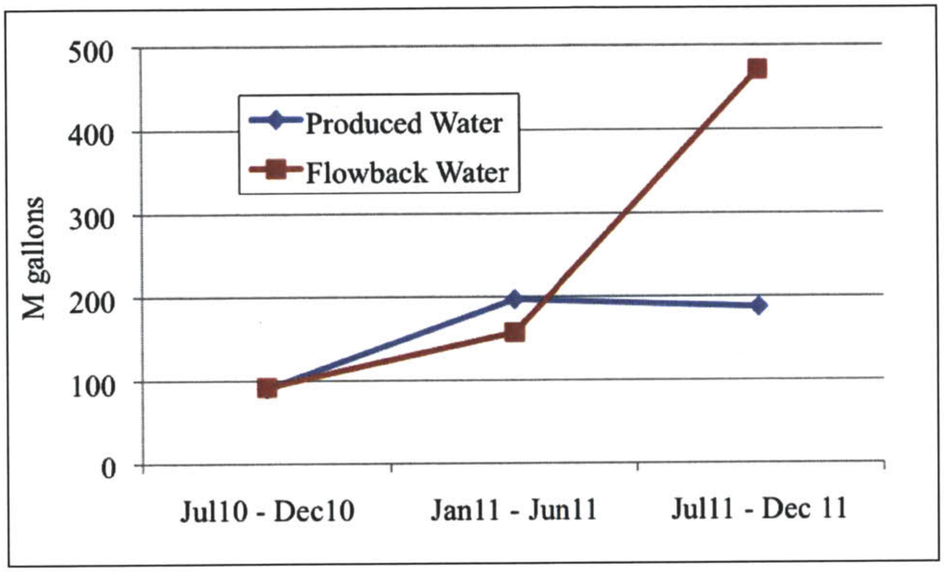

Figure 13 – Flowback and Produced Water Volumes for Marcellus shale, PA

	Produced Water [M gallons]	Flowback Water [M gallons]	PA DEP Marcellus Shale Wells drilled	Flowback per well [M gallons per well]	Flowback recovery ratio[11]	Operating Marcellus Wells	Produced water per well [M gallons per well[12]]	Produced water and flowback recovery ratio[10]
Jul10 - Dec10	90	92	743	0.12	2.2%	2331	0.04	2.9%
Jan11 - Jun11	197	157	808	0.19	3.5%	3363	0.06	4.5%
Jul11 - Dec 11	187	471	1129	0.42	7.5%	3644	0.05	8.4%

Table 7 – Flowback and Produced water recovery ratios in Marcellus shale (PA DEP, 2012)

[11] Based on a fracturing fluid volume of 5,6M gallons (Table 3)
[12] This value is for a 6 month period

The Marcellus flowback and produced water recovery ratios shown in Table 7 are much lower than expected. Furthermore, the 3-fold increase in flowback water shown in Figure 13 during 2011 is too high when compared to the 50% increase in wells drilled during that period. The PA DEP has only recently started collecting the data for the Marcellus shale and given the inconsistent data there are reasons to believe that there might be data collection issues for the first two collecting periods. For that reason, the recovery ratios shown from July 2010 to June 2011 are very likely underestimating the true value of wastewater recovered. Several conversations with producers indicate that combined flowback and produced water recovery is close to 15%.

3.5. Water Management Options

Managing both flowback and produced water from shale gas wells can be a challenge. There are three main water management options:

A) Water injection in disposal wells

B) Reuse in hydraulic fracturing operations

C) High level treatment (desalination) for surface discharge or beneficial use

The above management options have restrictions and limitations with regards to their application. The option to inject wastewater in disposal wells is not widely available in certain shale plays, particularly the Marcellus shale, due to the geology of the region as well as regulatory constraints. As a result, Marcellus producers need to truck water over long distances to inject water in disposal wells located in different states, notably Ohio. Depending on the distance travelled this might render this water management option uneconomical. Reuse options are limited by the composition of the flowback water and the capabilities of treatment technologies. Certain composition specifications need to be met before water can be reused for hydraulic fracturing. Depending on the salinity of the flowback water this can be achieved by cheap treatment methods, like filtration and blending, or by expensive, energy intensive methods, like thermal distillation. Extremely high salinity waters may not be able to be treated and reused onsite. Wastewater treated to the required effluent limits (see Section 2.4.6 for PA) can be discharged to surface waters after treatment at a Centralized Wastewater Treatment (CWT) facility. Capacity and availability of treatment facilities and their proximity to the well sites govern the economic viability of this wastewater management method.

Given the above water management options and their limitations, there are three primary treatment goals that need to be achieved. The first goal is to reduce the volume of wastewater requiring disposal. There should be an incentive to employ water reuse policies, since this will help reduce both disposal and trucking costs. Effective water reuse is highly depended on the composition of the water (see discussion in Chapter 4), therefore the second goal is to reduce the salts concentration, scaling risk and bio-fouling risk before reuse. If the objective is to perform surface discharge rather than reuse, then the goal would be to meet the regulatory discharge limits (Section 2.4.6) through treatment at a Centralized Wastewater Treatment (CWT) facility. The last goal is to minimize waste streams, which can lead to significant cost savings. All treatment processes result in a waste stream whether that is liquid (concentrated brine), solid (salt cake) or both which need to be disposed (Alleman, 2011). Minimizing waste streams can be achieved if the concentrated brine is used as an input stream to another industrial process or used as road salt.

Options	Important Factors and Comments		Approximate cost
Disposal wells	Regulation	Limited by regulation (only 8 injection wells in PA[13]). No new permits.	$0.7-10/bbl[14] ($1-2M capital investment)
	Capacity	Limited capacity (~1000 bpd per well)	
	Cost	High transportation costs to OH for disposal	
Publicly Owned Treatment Works (POTW) - Municipal	Regulation	No longer permitted based on PA DEP regulations (April, 2011) (Appendix D)	$0.75 - $2.00/bbl (processing cost)
	Treatment	Removes suspended solids and biodegradable material. Does not address salinity or TDS. Can not treat high salinity effluent	
	Capacity	Limited (typically 1% of average daily wastewater flow from well)	
	Cost	High transportation cost	
Centralized Wastewater Treatment (CWT) - Commercial	Regulation	Needs to comply with PA DEP discharge regulations and obtain NPDES permit	$2.75 - $5.00/bbl (processing cost)
	Treatment	New CWT facilities remove metals and salts	
	Capacity	Up to 260,000 gallons/day (higher than POTW). New units can potentially reach higher capacities.	
	Cost	High transportation and disposal cost	
Blending and reuse	Treatment	High potential for well plugging	$0.5 - $1.50/bbl
	Cost	Large potential savings from avoided disposal fees, lower freshwater purchase and avoided trucking costs.	
Onsite treatment and reuse	Treatment	Moderate potential for well plugging	Depends on treatment technology used (see Section 5.3)
	Cost	Large potential savings from avoided disposal fees, lower freshwater purchase and avoided trucking costs.	

Table 8 – Water Management Options (A detailed cost analysis is presented in Chapter 6) (Acharya et al., 2011; Gaudlip et al., 2008; Veil & Puder, 2006; Veil & Argonne, 2010; Vidic, 2011; Antero Resources, 2011)

Conventional water disposal includes injection in disposal wells and surface water discharge after treatment at a municipal or commercial treatment facility (see Figure 14). As discussed earlier, the PA DEP has recently enacted regulations that limit surface discharge from oil and gas operations to less than 500 ppm TDS (among discharge limits

[13] October 2011. Personal communication with PA DEP
[14] The mean cost is approximately $1/bbl and very few disposal costs go above $3/bbl

for other specific constituents such as chlorides, sulfates, barium and strontium) making it more expensive to treat water for surface discharge.

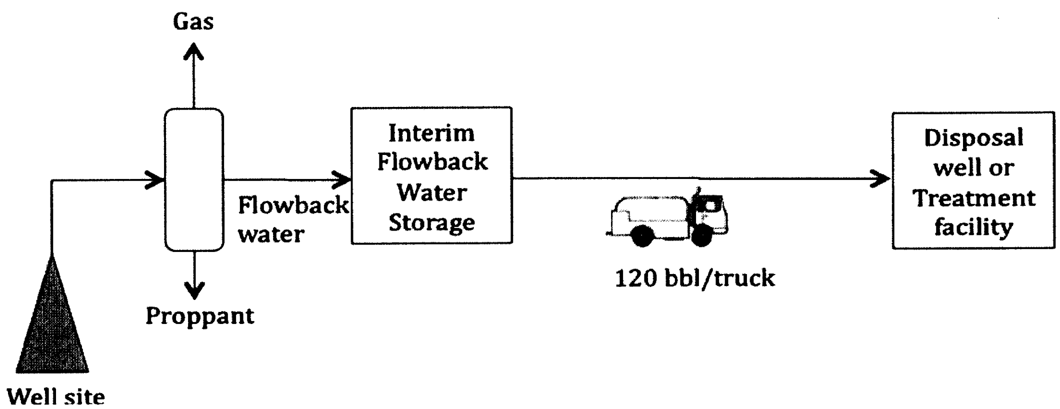

Figure 14 – Conventional Flowback Water Handling and Disposal[15] Operation at a Shale Gas Well Site (Acharya et al., 2011)

Due to high transportation costs, operators are now using unconventional treatment methods by blending, treating and reusing the flowback water (see Figure 15). The main benefits of flowback water reuse are reduced fresh water consumption; reduced water transportation related traffic on roads and reduced water disposal costs. The financial and social costs associated with hauling fresh water to the well site are reduced but not eliminated. Approximately 15% of the fracturing water returns to the surface as flowback therefore fresh make-up water is necessary in order to blend and dilute the concentrated flowback water as well as to top-up a new batch of fracturing fluid.

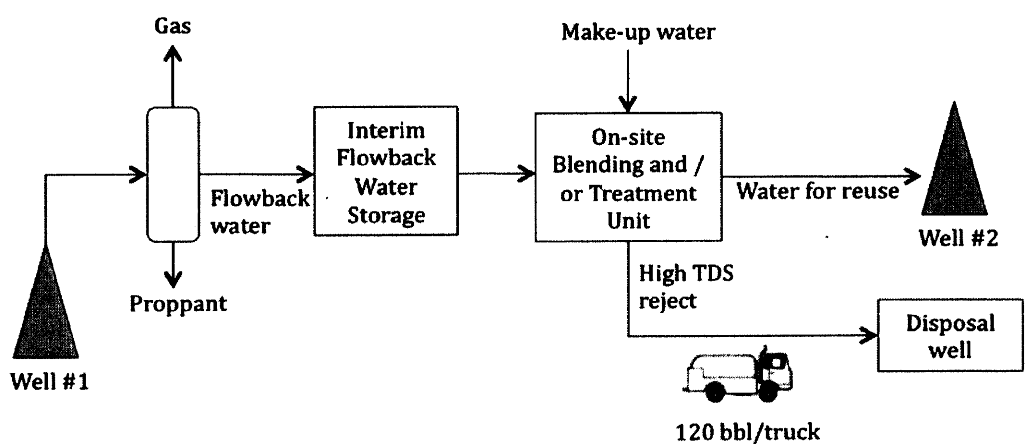

Figure 15 – Unconventional Flowback Water Handling for Reuse in Hydraulic Fracturing Operations. In some cases there is only a blending unit and no treatment takes place before reuse. (Acharya et al., 2011)

[15] Disposal refers to disposal wells and surface discharge

The main water management methods: disposal, treatment for discharge/beneficial use and treatment for reuse; are described in the following sections.

3.5.1. Disposal Wells

Injection in disposal wells is often chosen if there is an inexpensive, abundant supply of fresh water nearby and nearby disposal wells are able to handle the flowback volumes. As fresh water availability decreases and/or distance to disposal wells for injection increases, the disposal water management option becomes less appealing.

Disposal wells for injection of brine associated with oil and gas operations are classified as Class IID in EPA's Underground Injection Control (UIC) program and require federal permits. For an explanation of Class II disposal wells please refer to Appendix B. The EPA regulations assure that disposal wells meet the requirement of the Safe Drinking Water Act (SDWA). Injections include industrial discharges and a disposal well is not allowed to contaminate any portion of an aquifer that supplies a public water system or is capable of supporting a public water system. Also UIC regulations prohibit the movement of fluid that may pose a potential endangerment to an underground source of drinking water. It is important to note that produced water re-injected in disposal wells is not considered a pollutant under the RCRA Act and thus does not require treatment prior to injection.

Disposal wells receive untreated wastewater that is pumped in deep, impermeable rock layers. According to EPA hydrologist Karen Johnson anywhere east of Mississippi you are likely to find an underground aquifer within a quarter mile (Smith-Heavenrich, 2009). This makes the geology in Pennsylvania unsuitable for disposal wells. In Pennsylvania there are currently only 8 active disposal wells (Phillips, 2011; Yoxtheimer, 2012) while in Ohio there are approximately 200 underground disposal wells (Marcellus Effect, 2012; AWI, 2011). For comparison, Texas had approximately 12,000 Class IID disposal wells (McCurdy, 2011). According to Gaudlip et al. (2008) the average injection rate of the disposal wells is less than 1,000 barrels per day (bpd). This is reinforced by the PA DEP (2011a) database. Most disposal wells have injection rates lower than 1000 bpd while a handful of wells have injection rates of up to 2000 bpd. The capacity of disposal wells in Pennsylvania is not sufficient to handle the anticipated flowback and produced water flows. A considerable amount of Marcellus wastewater from Pennsylvania is trucked to out-of-state locations, notably Ohio and occasionally to West Virginia. High transportation costs make this an expensive disposal option.

3.5.2. Treatment for Surface Discharge or Beneficial Use

Publicly owned treatment works (POTW)

As gas production ramped up in the Marcellus in the 2008-09 period, significant volumes of flowback water were disposed of at publicly owned treatment works (POTW) and direct discharging Centralized Wastewater Treatment (CWT) facilities. In PA the two different POTW stations are situated in the eastern and western portions of the Marcellus play. The eastern POTW is located in Williamsport, Pennsylvania and discharges into the Susquehanna River. The western POTW is located in Waynesburg, PA and discharges in to a tributary of the Monangahela River (Blauch et al., 2009). In April, 2011, the Pennsylvania Department of Environmental Protection (PADEP) passed regulations establishing effluent standards for treatment of flowback water and raised concerns that POTWs only dilute the water, rather than treating it prior to discharge. After a request by the PA DEP, the oil and gas industry voluntary ceased shipping flowback water to POTWs in May 2011.

Centralized Wastewater Treatment (CWT)

In mid-2011, in Pennsylvania there were 18 grandfathered facilities offering treatment and disposal (Kasey, 2012). These are facilities that do not meet the new PA DEP wastewater treatment standards but because they were in operation prior to August 2010 and they are not located in areas with water quality problems, they may continue to operate as they have been, until they propose to expand or increase their existing daily discharge load. The above facilities remove metals, oils and minerals but do not remove salts. Some of these facilities have started to recycle Marcellus wastewater by treating it partially for reuse. This allows them to utilize their extra capacity without discharging more than the allowable grandfathered quantity of water. Some facilities produce a concentrated brine solution that is then either sent to a local company that will evaporate the brine to produce salt or is transported to a disposal well in Ohio (Veil & Argonne, 2010). Due to high transportation costs, it is important to locate the CWT facilities close to hubs of oil and gas wells. Beneficial use of wastewater could involve the use of concentrated brine to produce road salt or the use of concentrated brine as an input to industrial processes.

During July to December 2011, there were 15 active facilities in Pennsylvania receiving wastewater from shale gas operations at an average rate of 208,000 gallons per day (PA DEP, 2011a). During the same period there were an additional 14 active facilities active in Ohio but operating at a much lower average rate of about 7,000 gallons per day. New or expanding facilities need to employ desalination techniques (thermal distillation, mechanical vapor compression etc.) in order to meet the PA DEP requirements. Up to mid-2011, there was only one facility, Eureka Resources in Williamsport, which was meeting the PA DEP discharge requirements and produced distilled water through thermal distillation treatment (Kasey, 2012).

3.5.3. Treatment for Reuse

Onsite Treatment Units and Reuse Strategies

Treatment and reuse strategies involve high-level treatment of the flowback water (lime softening, reverse osmosis, distillation etc. – see Chapter 5 for details) producing a fresh water quality product. The treated water is usually blended with make-up water from freshwater sources to generate a full batch low TDS fracturing fluid. Treatment and reuse is used when fresh water costs are high or a high quality, low TDS fracturing fluid is desired. Producers that transfer the fracturing fluid via temporary above ground pipelines (known as fastlines) may choose the recycling option to minimize the potential environmental liability from a spill or fastline rupture. There are several issues that complicate the adoption of onsite treatment units. Firstly, the variability in flowback water chemistry across the Marcellus shale means that certain mobile treatment units will not be applicable for the whole play thus limiting their utilization potential. Secondly, the use of different amounts and types of fracturing fluid additives by different operators and at different locations can make it challenging to reproduce fracturing fluid at the desired specifications through the treatment of flowback water. High-level treatment processes have high capital cost and energy requirements making this an expensive water management option.

Blending and Reuse strategies

Blending and reuse strategies involve treatment of the flowback to remove suspended solids and soluble organics and then blending the treated water with fresh make-up water to dilute the concentrated flowback water generate a low TDS fracturing fluid for new wells. Reuse strategies reduce the amount of fresh water required and can minimize the need for wastewater disposal provided all of the flowback can be treated and reused. In areas with high disposal costs, reuse strategies may be the most economical option. A risk with using this option is that the resulting fracturing fluid could have higher than optimal concentration of contaminants (TDS, hardness, bacteria etc.). This can affect the fluid stability by reducing the effectiveness of friction reducing agents or have other undesirable impacts on the fracturing process, like scaling and swelling inside the well fractures. Another barrier to this management method is scheduling issues. Flowback water for reuse might be available at a time when there are no fracturing jobs scheduled. In that case, the blending and reuse is not a feasible management option unless the operator has significant storage facilities.

3.5.4. Transporting Water

Water transportation, in terms of both transporting fresh water to the well site for fracturing and transporting wastewater away, involves significant costs. The rapid shale gas developments in the northeast mean that the industry operations are growing in a location that does not have the appropriate infrastructure to deal with waste management issues at such a large scale.

The most widely used option for transporting water is trucking. Given that the disposal wells are located in Ohio while most of the drilling activity in the Marcellus is in Pennsylvania, the distances the water needs to travel before it is disposed are often significant. The Appalachian Shale region is 300 miles wide, therefore if any of the eastern located wells needs to dispose of its wastewater, the predominant cost of the disposal operations will be trucking. Other transportation options such as pipeline and railroad transfers are not readily available. Temporary pipelines have been installed in certain cases, especially to source water from a nearby river or storage facility. The infrastructure for railroad transfer is not widely available in Pennsylvania and getting the water to the railroad would still involve significant trucking distances. See Section 6.1 for detailed trucking costs.

3.6. Water Management Options in Marcellus, PA

The Pennsylvania Department of Environmental Protection (PA DEP, 2011a) has been releasing production and wastewater information for the Marcellus shale. The data collection process is a recent effort to present more transparency to this topic. The databases released include information about the different waste management methods used for flowback and produced water as well as a breakdown for the amounts of wastewater, treatment methods and treatment facilities used by each operator.

Waste management methods for produced and flowback water

Figure 16 illustrates the water management methods used for produced and flowback water. It is noted that flowback water is not sent to disposal wells but rather is being reused or sent to CWT facilities. A possible explanation for this could be the difference in salinity between produced and flowback water. Produced water is expected to be more saline than flowback water (see Chapter 4), mainly because it remains in the reservoir for a longer period of time. Treating mainly flowback water at centralized treatment facilities and sending saline produced water to disposal wells might be more effective and economical since water with lower salinity requires lower energy for treatment thus lowers the cost. Moreover, lower salinity water reduces the chances for fouling and scaling in treatment equipment. An alternative reason for not sending flowback water to disposal wells is because of the high flow rates at which flowback water needs to be managed. Flowback water has an approximate flow rate of 1,500 bbl per day[16] for every well drilled. A typical Ohio disposal well is able to handle approximately 1000 bpd (Gaudlip et al., 2008) with few cases accepting up to 200 bpd (PA DEP, 2011a). Therefore disposal well options may not be able to deal with the required injection flow rate without some kind of temporary storage facilities.

Water reuse is also a dominant water management method. Reuse capabilities are limited by the composition and amount of the wastewater. A resulting fluid with the desired composition for re-fracturing (see Section 4.3) can be attained through blending or onsite treatment of flowback water. This can be achieved at a lower cost by using lower TDS flowback water rather than higher TDS produced water. Reuse capabilities are also limited by the drilling activity of operators and how much water they need for future fracturing jobs. Thus, even though in terms of volume and composition all wastewater could be recycled, if there is no use for the treated water it is more cost effective to send the contaminated water to a CWT for surface discharge.

In 2011, for the total volume of both produced and flowback water 61% is sent to CWT facilities, 31% is reused and 8% is sent to disposal wells.

[16] Assumes that 15% of a 5.7M gallon fracturing fluid returns as flowback in 14 days

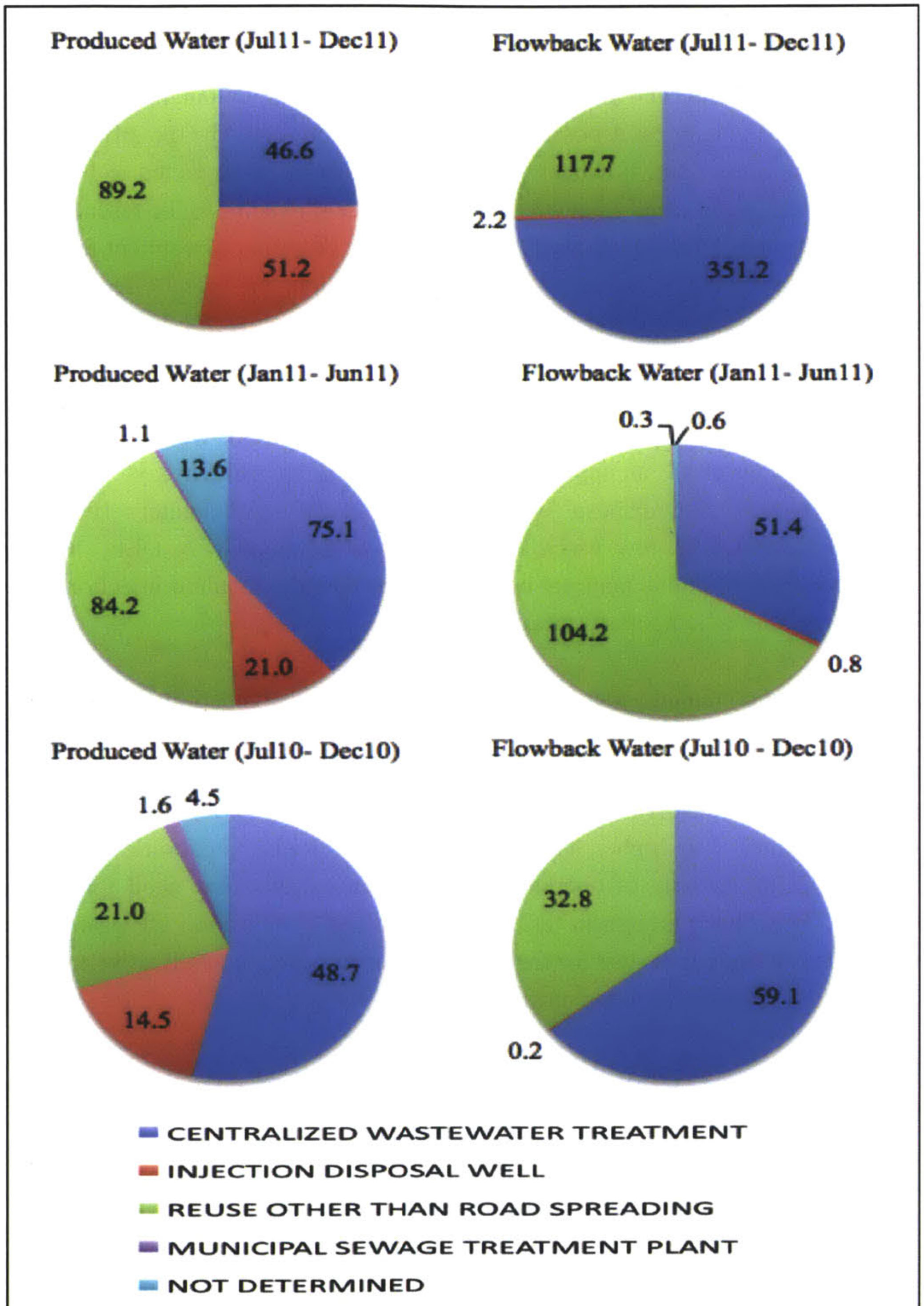

Figure 16 – Breakdown of water management methods for produced and flowback water in Pennsylvania from 2010Q3 to 2011Q4. All values are in million gallons. (PA DEP, 2011a)

Location of Waste Management Options

As shown in Figure 17 the majority of the wastewater sent for disposal well injection is transported to Ohio. 49% of the water that was injected in Ohio disposal wells during the first three months of 2011 was out-of-district water, mainly coming from Pennsylvania (AWI, 2011). Moreover, Centralized Wastewater Treatment facilities within the state of PA are insufficient for dealing with the wastewater treatment needs of Marcellus producers. Throughout 2011 some water had to be transported to Ohio for treatment. It is likely that wastewater is transported to Ohio because of lack of capacity within Pennsylvania but another reason could be due to proximity. Wells located to the west side of Pennsylvania might be closer to treatment facilities in Ohio thus transporting water there could minimize transportation cost.

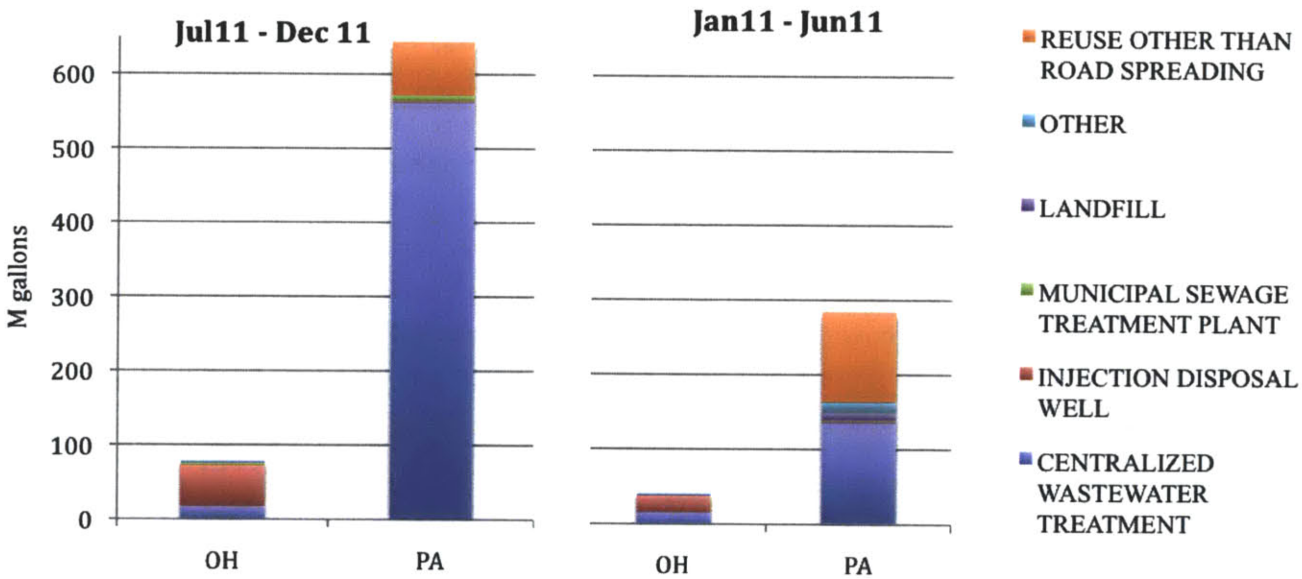

Figure 17 – Wastewater management options for Pennsylvania shale gas wastewater – Breakdown by disposal locations (Ohio – OH; Pennsylvania – PA) (PA DEP, 2011a)

Large Vs Small Operators[17]

Large operators are recycling 31% of the combined flowback and produced water, while small operators recycle 40%. This implies that both operators have a similar attitude towards recycling and reusing wastewater. While the absolute numbers for recycling are orders of magnitude different this does not imply a difference in the operator's tendency to reuse water. Small operators are limited by the fact that they are drilling far fewer wells, therefore they have less flowback water to recycle and the timing at which flowback is received might not be the right time to reuse the water for an additional fracturing job. Thus, even though in terms of volume and composition all wastewater from the small operators could be recycled there might not be any use for it, which forces the operators to use other water management options.

Certain large operators like Cabot Oil & Gas Corp, Energy Corp of America and Talisman Energy are reusing 100% of their flowback water (PADEP, 2011; Blauch et al., 2011). This is possible if the TDS of the flowback water is low and treatment is used to remove hardness constituents (Blauch et al., 2011). All three operators mentioned above are large operators who have extensive drilling activities in the Marcellus shale. This gives them the capability to possibly reuse all the wastewater for subsequent fracturing jobs since fracturing jobs should occur fairly frequently. Alternatively, it is possible that the above three operators have production operations in areas with low TDS flowback water that allows them to reuse water after simple filtration and blending procedures, without requiring any further expensive treatment processes.

[17] Large operators are defined as having more than 20,000 bbl of produced water during a 6 month period

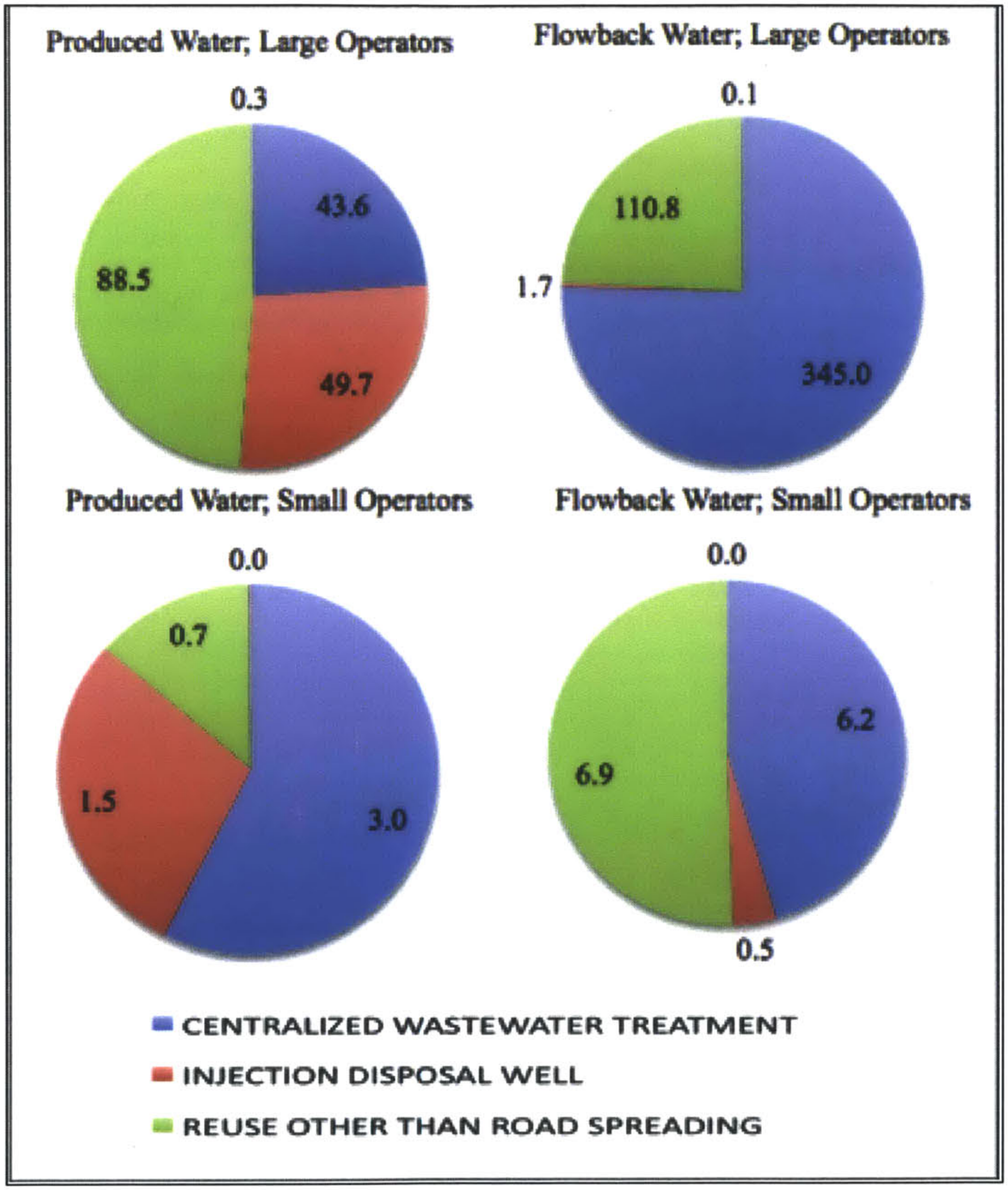

Figure 18 – Differences in wastewater management options for Pennsylvania shale gas wastewater used by large and small operators. Large operators are defined as having more than 20,000 bbl of produced water[18] for a given time period. All values are in million gallons for the period July 2011 to December 2011 (PA DEP, 2011a)

[18] Produced water correlates to the number of wells that are currently in production and thus gives a good indication of the activity of each operator

4. Chapter 4 – Water Geochemistry

The composition of flowback and produced water defines the type of technologies that can be used for water treatment. Understanding the composition of the water will help us understand how it can be treated effectively and what are the main components that need to be removed in order for the water to be suitable for reuse in subsequent fracturing operations.

Composition of flowback and produced water varies significantly because of the amount of time that the water spends within the reservoir. Constituents from the shale formation diffuse into the water and also saline water that may exist within the reservoir can flow to the surface as produced water. As mentioned in Chapter 3, flowback water recovered within the first few days of fracturing tends to be significantly "cleaner", with a lower concentration of contaminants than produced water. Therefore the technologies and water management approaches used to treat flowback and produced water often vary significantly.

4.1. Key Contaminants of Concern for Reuse

The contaminants in the flowback water and their impact on water reuse for hydraulic fracturing are shown in Table 9. The key aspects of these contaminants for evaluating water treatment technology options are described in this section.

Flowback water: Key Contaminants	Impact for reuse
- Particulates - Total Suspended Solids (TSS)	Plugging
- Free Oil and Grease - Dissolved Organics - Volatile Organics	Affect fluid stability
- Total Dissolved Solids (TDS) - Chlorides	Affect fluid stability (mainly the friction reducing agents); Corrosion; Increase cost of treatment
- Iron - Hardness ions: - Ba^{2+}, Mg^{2+}, Ca^{2+}, Sr^{2+}, Mn^{2+} (divalent cations) - Sulfates, SO_4^{2-} - Silica	Scaling in piping, equipment and well fractures by forming insoluble precipitates
- Biological counts	Bacteria growth causes swelling inside the fractures
- Naturally Occurring Radioactive Materials (NORM)	Radioactivity

Table 9 – Key contaminants that can affect fracturing fluid reuse

Particulates could be precipitated solids, sand and silt, clays, proppants, corrosion products, and other solids derived from the formation and well bore operations. Quantities can range from insignificant amounts to high enough to yield solid slurry. These should be amenable to removal via filtration or other mechanical means.

Total Suspended Solids (TSS) are finer particulates of inorganic, metallic or organic materials. They can also be colloidal. Reported values are typically ~ 200ppm but could be much higher depending on the particular operating conditions of the flowback. There could be significant variability in the values during the flowback (Acharya et al., 2011). The TSS measurement is conducted by passing the water sample through a 1.0 micron filter and weighing the residue material after drying. Turbidity, measured in NTU (Nephelometric Turbidity Units), refers to the transmission of light through water samples.

Total Organic Carbon (TOC) is a measure of the amount of combustible organic carbon present in the wastewater. High molecular weight dissolved organic material in the flowback water may reduce the effectiveness of friction reducing agents, thus reducing fluid stability. Dissolved organic material can also act as a food source for bacteria. TOC includes free oil and grease (FOG), dissolved organics and volatile organics. Free oil and grease (FOG) could be from the oils and diesels from compressors and other drilling equipment on the well site. There could be significant variability in the values during the flowback. Dissolved Organics could be small amounts of low molecular weight hydrocarbons, such as polymers used as friction reducers, or other organics from the formation. Some of the dissolved and undissolved organics could be considered as volatile organics under normal operating conditions and as such may present concerns with emissions or as fire hazards if the concentrations are too high. Condensates present in the shale gas that contaminate the flowback water, especially benzene, toluene and xylenes, need to be explored as they are of public concern.

Naturally Occurring Radioactive Materials (NORMs) originate in geological formations and can be brought to the surface with the flowback water. The most significant radionuclide contributing to oil and gas is radium. It is fairly soluble in saline water and has a long radioactive half-life of about 1600 years. Uranium and thorium could also be found in the reservoir but have very low solubilities (NYS, 2009).

Silica could be colloidal silica or reactive silica; the former is of concern as a potential fouling agent for desalination membranes (Amjad et al., 1997; Zhu & Elimelech, 1997). Colloidal silica exists as long polymer chains and exhibits no ionic character. Reactive silica is soluble silica that is slightly ionized and has not been polymerized into a long chain. Removal of colloidal silica may occur during removal of suspended solids and filtration but removal of reactive silica requires ion exchange processes or reverse osmosis.

Hardness is comprised of potential scale-forming ions such as divalent and trivalent cations (which includes Calcium (Ca^{2+}), Magnesium (Mg^{2+}), Barium (Ba^{2+}), Iron (Fe^{2+}), Manganese (Mn^{2+}) and Strontium (Sr^{2+}) ions), and divalent anions, such as sulfates (SO_4^{2-}) and carbonates (CO_3^{2-}). Ions of most concern are Ba^{2+}, Ca^{2+} and Sr^{2+} because of their high affinity to form precipitates. The concentrations of these ions are high in certain shale plays, such as the Marcellus shale while low in shale plays such as Woodford and Fayetteville. They could range from ~100 ppm to 10,000 ppm depending on the shale and vary as a function of flowback time (increase almost linearly with TDS) (Acharya et al., 2011; Blauch et al., 2009). Barium ions as a contaminant are a concern due to the very high concentration in most plays. Since $BaSO_4$ has very low solubility, when Ba^{2+} concentration is high, SO_4^{2-} concentration is low, and vice-versa. Reported barium values are as high as 6,000 ppm in certain areas of Marcellus shale (Acharya et al., 2011). Within the Marcellus shale there are significant variations in barium concentration across the formation.

Iron and Manganese ions are also a concern as they may oxidize and form precipitates with various anions.

Total Dissolved Solids (TDS) refers to a measure of all inorganic solids dissolved in the water. It accounts for ions that contribute to water hardness, like calcium, but also those that do not, like sodium and silica. The TDS measurement is a better reflection of the total mineral content of the water rather than the water hardness measurement.

This thesis concentrates on the negative effects of high hardness and TDS levels in order to determine the required treatment procedures for hydraulic fracturing wastewater prior to effective re-use in subsequent fracturing operations.

4.1.1. Where Do The Contaminants Come From?

Key elements observed in the Marcellus Shale bulk core and salt layers are common to the elements found in flowback and produced water. Salt layers involve salt precipitation along the parting planes of the formation. Common cations include Ba^{2+}, Sr^{2+}, Ca^{2+}, Na^{+}, Fe^{2+}, Mg^{2+} and K^{2+}. These, with the exception of potassium, are not consistent precipitants one would expect from well drilling and well completion operations since they are not used as additives to the hydraulic fracturing operations.

Cation	Bulk Core	Salt Scraping
Ba^{2+}	1%	2%
Ca^{2+}	40%	42%
Fe^{2+}	46%	5%
K^{+}	4%	7%
Mg^{2+}	6%	3%
Na^{+}	2%	40%
Sr^{2+}	1%	1%

Table 10 – Relative soluble cation content in the Marcellus Shale formation (Blauch et al., 2009)

The salinity of flowback and produced waters from Marcellus are high compared to other formations. Table 10 illustrates the high proportion of sodium ions indicating a strong presence of sodium chloride, NaCl. Furthermore the strong presence of Ca^{2+} and Fe^{2+} ions indicates the high risk of precipitate formation that can cause scaling inside the fractures. Ba^{2+}, Mg^{2+} and Sr^{2+} ions, even though they are present in small percentages, can form highly insoluble compounds (see Section 4.1.4) and cause scaling. The source of potassium is probably from potassium chloride, KCl, added to the hydraulic fracturing fluid, therefore it is usually desirable to retain it in the product water for fracturing reuse (Acharya et al., 2011).

4.1.2. Total Dissolved Solids (TDS)

TDS values vary significantly in different formations (see Table 11) and, while they do not present a problem in certain locations, in the Marcellus shale high salinity is one of the main drivers for high treatment costs. High salinity restricts the type of technology that can be used to treat the feed water to the required levels and requires higher amounts of energy for distillation treatment. The average values of TDS shown on Table 11 represent a combined mean for flowback from a well while the maximum is an instantaneous value. Actual values will vary widely from the numbers given below depending on the well location, well geochemistry and other factors. The TDS levels increase with flowback volume (see Figure 19 as an indication of the increase of TDS over time), and the rate of increase depends on the chemical composition and structure of the shale formation.

Shale	Average TDS, ppm	Maximum TDS, ppm
Fayetteville	13k	20k
Woodford	30k	40k
Barnett	80k	>150k
Marcellus	120k	>280k
Haynesville	110k	>200k

Table 11 – Average and instantaneous TDS values for shale formations (Acharya et al., 2011)

4.1.3. Chlorides

Chlorides are by far the greatest contributor to TDS. Chloride ions, found in sodium chloride (NaCl) salts, are soluble in water therefore do not present a risk for scaling or plugging the well fractures. However, chlorides affect the fluid stability of the fracturing fluid and reduce the effectiveness of the friction reducing agents. Furthermore, high TDS wastewater treatment technologies, like distillation, have a high energy requirement and are thus more costly.

Various sources quote a linear relationship between TDS and Chlorides (Acharya et al., 2011 Gaudlip et al., 2010; Hayes, 2009; Blauch et al., 2009). The above sources have also reported data on flowback composition as a function of time. The relationship reported in the literature between chlorides and TDS in flowback water is the following: $Chlorides\_concentration = 0.61 * TDS\_concentration$. Flowback data from Blauch et al. (2009) is shown in Table 12 and is used to verify the relationship between chlorides and TDS. The analysis is shown in Figure 19 and the average ratio of chlorides to TDS is 59.5% ($Chlorides\_concentration = 0.595 * TDS\_concentration$). This is close to the expected value of 61% mentioned above and the data indicates that a linear relationship is valid.

Samp Date	TDS	Ca (mg/L)	Mg (mg/L)	CaCO3	Na (mg/L)	K (mg/L)	Fe (mg/L)	Ba (mg/L)	Sr (mg/L)	Mn (mg/L)	SO4 (mg/L)	Cl (mg/L)
4/15 pre-frac	224.38	15.00	2.73	49.44	18.00	1.65	0.25	0.23	0.46	0.06	3.00	183.00
4/26	84839	7100	603	23286	22800	326	3.93	2000	1400	6.69	0.00	50600
4/27	89861	7640	651	24952	24300	346	7.80	1990	1510	7.07	8.87	53400
4/27	105169	8490	714	27432	25100	352	9.70	1870	1670	7.44	156	66800
4/28	116266	10500	893	33879	29400	410	35.30	1980	2200	9.10	139	70700
4/29	123902	11700	996	38419	31100	437	16.20	2480	2860	9.50	2.94	74300
4/30	164081	16700	1400	52071	41700	579	23.50	2230	2570	13.00	165	98700
5/1	140169	14000	1150	44358	34300	477	28.70	2290	2590	11.00	22.70	85300
5/2	146539	16700	1380	53473	39400	535	30.20	3000	3380	13.10	0.19	82100
5/3	161636	17100	1410	54446	40400	543	35.20	2950	3280	13.30	4.97	95900
5/4	164902	16700	13000	103026	37000	496	32.90	3850	4310	12.30	1.15	89500

Table 12 – Flowback Analysis Data from a Marcellus Shale well (Blauch et al., 2009)

Day	Chlorides / TDS ratio
0	
11	59.6%
12	63.5%
13	60.8%
14	60.0%
15	60.2%
16	60.9%
17	56.2%
18	59.6%
19	54.2%

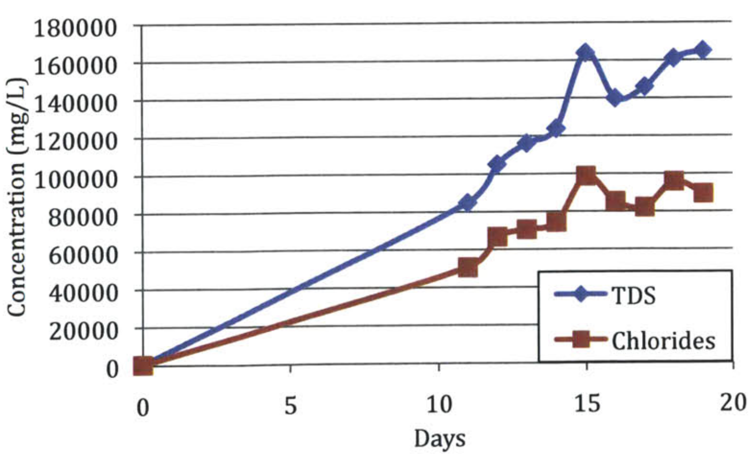

Figure 19 – TDS and Chlorides concentration over time from Marcellus shale flowback

The average chlorides concentration is 59.5wt% of the TDS. This value is very close to the value of 60.8wt% that would occur if the TDS was entirely due to sodium chloride, NaCl (based on molecular weight ratio, $M_{Cl}/M_{NaCl} = 35.5/58.5 = 0.608$). However, the sodium ion (Na^+) content in Table 12 corresponds to only 25.1wt% instead of 39.2wt% which is the concentration in pure NaCl. This implies that chloride ions are forming salts with other ions in the formation, and groundwater supplies (main source for NaCl) is not the only source for chloride ions.

Acharya et al. (2011) provides data for the chloride concentration in the first 15 days of flowback. The TDS concentration is estimated in Table 13 to determine whether low TDS water treatment processes can be used at the beginning of the lifetime of the well.

	Chlorides concentration (ppm)	**Estimated TDS (ppm)**
Day 5	20k – 70k	33k – 115k
Day 10	40k – 90k	66k – 148k
Day 15	55k – 110k	90k – 180k

Table 13 – Chlorides and estimated TDS concentration for Day 5 to 15 for an average Marcellus shale well (Acharya et al., 2011)

From the above data, we observe that low TDS water recovery process may have limited applications in the Marcellus shale. However, a certain percentage of the flowback may be amenable to low TDS water treatment with appropriate water management to isolate the first <3-5 days of flowback water. This is further illustrated in the treatment technology section (Figure 24) when the applicability of different technologies over different timeframes is discussed.

4.1.4. Hardness Ions and Scaling Considerations

Chlorides are by far the greatest contributor to high TDS, however they are not the only limiting chemicals in enabling flowback water reuse. Scaling within the formation occurs when hardness ions precipitate, thus creating the potential for reduced permeability and ultimately reduced gas production. Water hardness is determined by the concentration of multivalent cations in the water. Hard water is not harmful to the public but it can pose problems to industrial equipment through scaling, which can damage or reduce the equipment functionality. Hardness of the water can mainly be removed using water softening techniques. These include lime softening and ion exchange resins.

Potential scale-forming divalent cations include Ca^{2+}, Mg^{2+}, Ba^{2+}, Fe^{2+}, Mn^{2+} and Sr^{2+}, and divalent anions, such as sulfates and carbonates. These can form ionic compounds, which can precipitate in the formation. The solubility product constant, K_{sp}, is used to describe the relative solubility of saturated solutions of ionic compounds. A saturated solution is in a state of dynamic equilibrium between the dissolved, dissociated ionic compound and the undissolved precipitate. Low solubility product constants indicate that the compound is insoluble at a given temperature. Solubility product constants are temperature dependent and are related to the Gibb's free energy change, ΔG, for the solution with the following relationship:

$$\Delta G = -RT\ln(Ksp) = \Delta H - T\Delta S \qquad (1)$$

where ΔG = Gibbs free energy of formation [J/mol]; ΔH = enthalpy of formation [J/mol]; ΔS = entropy change [J/mol*K]; R = Gas constant [8.314 J/mol*K]; T = Temperature [K]

Equation 1 was used to calculate the K_{sp} values at 100°C, which is an expected average temperature downhole. Table 14 shows the K_{sp} values at 25°C and 100°C.

Compound	**Formula**	**Solubility Product Constant at 25°C (K_{sp}) [mol^2/L^2]**	**Solubility Product Constant at 100°C (K_{sp}) [mol^2/L^2]**
Barium carbonate	$BaCO_3$	5.1E-09	2.4E-07
Barium sulfate	$BaSO_4$	1.1E-10	1.1E-08
Magnesium carbonate	$MgCO_3$	3.5E-08	1.1E-06
Magnesium sulfate	$MgSO_4$	Slightly soluble	Soluble
Calcium carbonate	$CaCO_3$	2.8E-09	1.5E-07
Calcium sulfate	$CaSO_4$	9.1E-06	9.4E-05
Strontium carbonate	$SrCO_3$	1.1E-10	1.1E-08
Strontium sulfate	$SrSO_4$	3.2E-07	6.5E-06

Table 14 – Selected Solubility Product Constants (Parks & Edwards, 2006; Dean, 1987)

As shown in Table 14, barium sulfate and strontium carbonate are the most insoluble compounds and present the highest risk for scaling. Calcium carbonate and barium carbonate would also present issues with scaling and low solubility but would not precipitate as fast as the other two compounds. At 100 °C the solubility product constants are still very low and indicate that the compounds remain insoluble. Barium, Strontium and Calcium ions present the highest risk for scaling.

Solubility product constants and Equation 1 are used to identify the temperature at which different concentrations of constituents can precipitate. Table 15 shows the results:

Barium concentration [Ba^{2+}] in Barium Sulfate [ppm]	**Temperature below which precipitate forms [°C]**
25	107
50	139
75	160
100	177
125	190
150	202
Strontium concentration [Sr^{2+}] in Strontium Carbonate [ppm]	**Temperature below which precipitate forms [°C]**
25	120
50	155
75	177
100	195
125	210
150	223
Calcium concentration [Ca^{2+}] in Calcium Carbonate [ppm]	**Temperature below which precipitate forms [°C]**
25	81
50	113
75	135
100	152
125	166
150	178

Table 15 – Temperatures at or below which ionic compounds are expected to precipitate. Analysis for barium sulfate, strontium carbonate and calcium carbonate.

As shown in Table 15, even with a concentration of barium and strontium as low as 25 ppm, precipitates will form at approximately temperature below 107°C and 120°C respectively. Calcium carbonate remains soluble at 100°C but precipitates at approximately 80°C. Barium carbonate forms precipitates at 100°C if the concentration for barium ions is greater than 100ppm. Strontium sulfate is less soluble and forms precipitates at 100°C if the concentration for strontium ions is greater than 500ppm. Calcium sulfate is the least soluble compound of the ones presented above and does not form precipitates at 100°C until the calcium ion concentration is 1300ppm.

Flowback composition varies significantly across the Marcellus shale. Figure 20 shows how the barium concentration in flowback water varies in several locations across the Marcellus shale. This reinforces the fact that any treatment solution for wastewater applied in the Marcellus shale will need to be tailored to the chemistry of the flowback in particular regions.

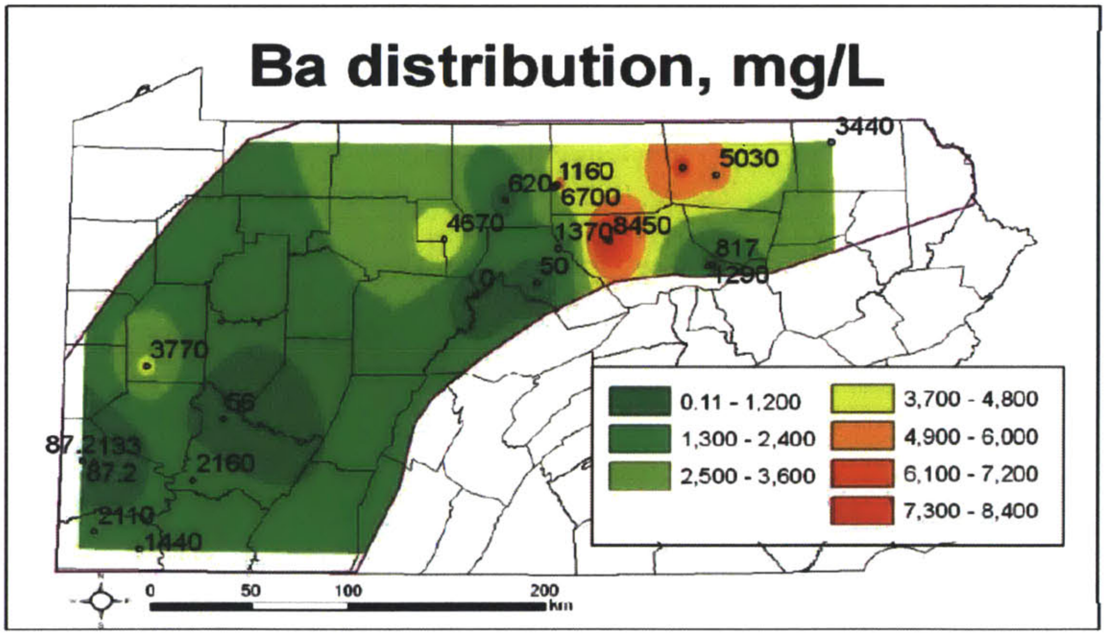

Figure 20 – Barium ion concentration across the Marcellus Shale (Kirby, 2011)

4.2. Chemical Analysis of Marcellus Flowback Water

This section analyzes time series flowback composition data from the Marcellus Shale and investigates how different chemicals and compound concentrations vary over time. Flowback time series data[19] provided by a private source is shown in Figure 21. The data can be used to illustrate the serious effects of scaling and how chemical concentrations can control the formation of precipitates.

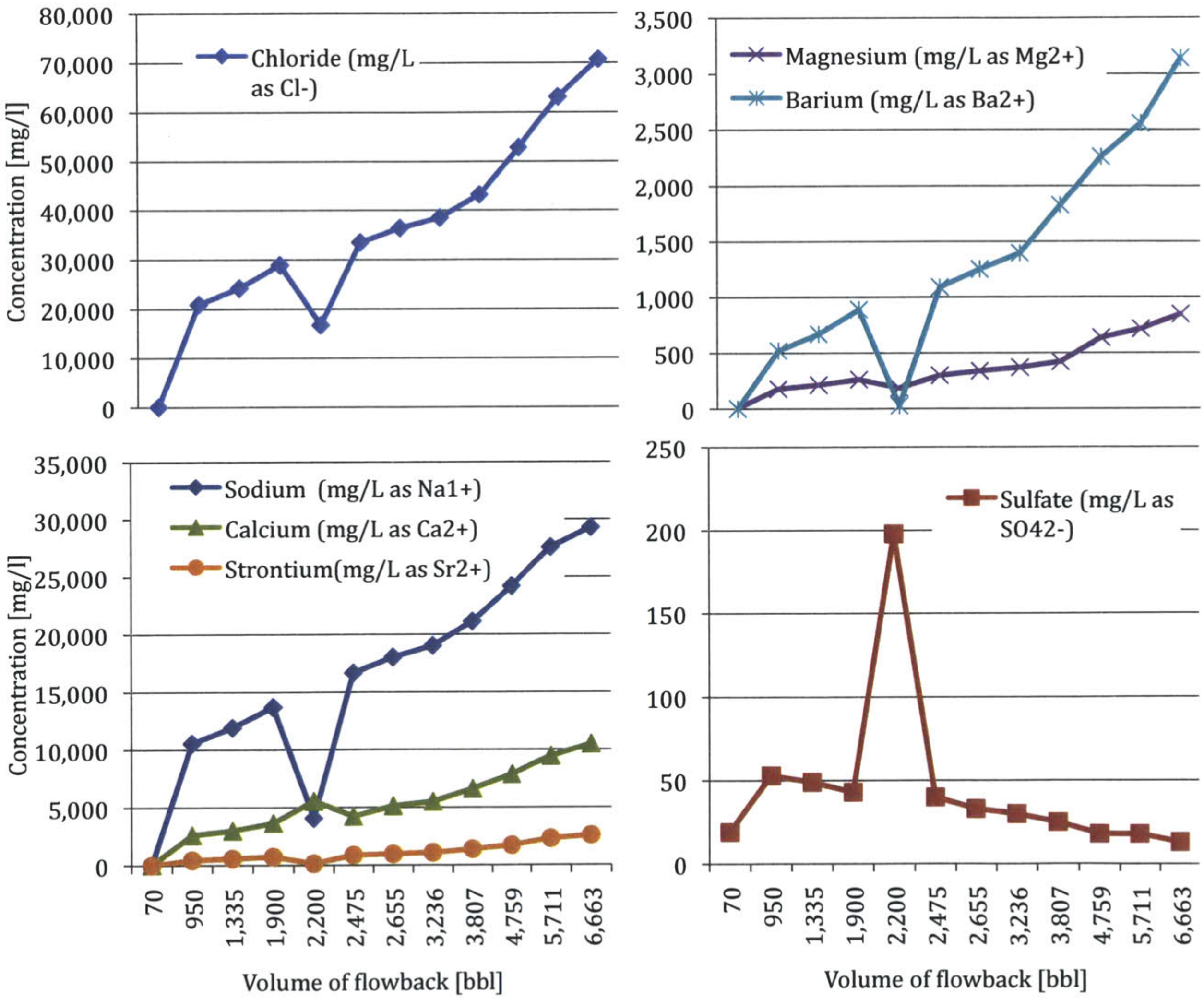

Figure 21 – Time series flowback composition data for the Marcellus shale. Note: Y-axes are all the same units but different magnitudes. X-axes are all the same units and magnitude.

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[19] Data provided from private source (Commercial entity)

The data shown in Figure 21 is used to analyze the geochemistry of the flowback sample in the Marcellus shale and provide general insights about how the composition of flowback varies over time. Chemical composition of this flowback sample can be classified as highly saline. The chloride concentration of 70,000ppm implies a TDS concentration of ~115,000ppm (Section 4.1.3) which is three times higher than seawater salinity. Sodium and calcium are the most prevalent cations. As expected, the amount of dissolved constituents increases as flowback progresses, likely due to longer residence time inside the formation. Eventually the produced water flowing out of the formation has no relationship to the injected fracturing fluid and is mostly comprised of the downhole saline groundwater.

Based on the information presented in Figure 21, sulfate scaling is likely since calcium and barium concentrations are rising while sulfate concentration is dropping. The sharp decrease in barium levels shortly after the sharp increase in sulfate ions suggests the formation of barium sulfate scale. The affinity of barium ions to form precipitates with sulfate is higher than other cations (see Section 4.1.4), which explains the sharp drop in the concentration of barium ions. Strontium also displays a decrease in concentration, which is expected since strontium has a strong affinity to precipitate with sulfates as well but not as high as the tendency that barium ions have to precipitate with sulfate ions. The solubility of barium sulfate is very low and it can become a very aggressive scale within the formation. Since $BaSO_4$ has very low solubility, when Ba^{2+} concentration is high, SO_4^{2-} is low and vice versa. The high concentrations of divalent ions (Ca^{2+}, Sr^{2+}, Ba^{2+}) imply that most of the ions are present in the form of chlorides, which are soluble in water at the solution temperatures.

A similar analysis to that shown in Figure 21 was performed by Blauch et al. (2009) for a different location in the Marcellus and can be found in Appendix E. Similar conclusions were drawn and the data trends are consistent among the two analyses.

Further insights can be concluded from data that was published by Acharya et al. (2011). Table 16 shows the composition of a flowback sample from a Marcellus shale well[20].

[20] The time series data was not provided for this well

Cations	mg/L
Calcium (Ca^{2+})	20,463
Magnesium (Mg^{2+})	1,987
Sodium (Na^{+})	37,063
Iron (Fe^{2+})	143
Potassium (K^{+})	296
Barium (Ba^{2+})	203
Strontium (Sr^{2+})	2,243
Manganese (Mn^{2+})	43
Anions	**mg/L**
Bicarbonate (HCO_3^-)	100
Sulfate (SO_4^-)	8
Chloride (Cl^-)	97,084
	mg/L
TDS	159,541
Gases	**mg/l**
Carbon Dioxide (CO_2)	481
Hydrogen Sulfide (H_2S)	2

Table 16 – Composition of a flowback sample from a Marcellus shale site (Archaya et al., 2011)

The concentration of the hardness ions (divalent – Ca^{2+}, Mg^{2+}, Ba^{2+}, Sr^{2+}) corresponds to 56,000 mg/L $CaCO_3$[21]. Ratio of [hardness ($CaCO_3$ basis)/TDS] is about ~0.35. This ratio varies amongst different shale plays from 0.2 to 0.35 depending on downhole soil conditions and the composition of the water used for fracturing (Acharya, 2011). This relationship can be used to estimate the level of hardness in the solution when choosing water treatment technologies. The iron content of 143ppm may be too high for reuse, especially since it is in the Fe^{2+} state, which may potentially get oxidized and form undesired precipitates that could cause scaling. Lastly, the observation made on the previous data set (Figure 21) with regards to hardness and sulfates concentration is also prevalent here. The sulfates concentration is low while the barium and strontium concentrations are very high, indicating that most of the sulfates have precipitated and formed scale.

4.3. Hydraulic Fracturing Fluid - Reuse Composition

The quality of water required to develop an effective fracturing fluid for reuse and how this impacts well production is a critical factor in developing a water management strategy. Multivalent ions and chlorides in the water can limit friction reducer effectiveness and drive up costs for the operators' pumping operation. The type and dose of friction reducer can be adjusted to accommodate for higher TDS water at an added cost (Horner et al., 2011). Scaling tendency of the source water and poor compatibility of reuse water with make-up water can result in scaling. The scaling can occur within the formation creating the potential for reduced permeability and ultimately reduced gas

[21] Hardness is reported on a mg/L $CaCO_3$ basis

production. Bacteria in the fracturing fluid can cause formation biofouling, reducing permeability and gas production. The presence of sulfate reducing bacteria can form hydrogen sulfide, making the well sour, creating safety issues and increasing overall costs (Horner et al., 2011). Metals in the water, specifically iron, can oxidize and form deposits, further reducing permeability and gas production. Suspended solids in the fracturing fluid such as sand, silt and clay particles can also lead to reduced permeability.

Several entities, including oil and gas operators and service companies, are developing specifications for reuse hydraulic fracturing fluid. This varies widely depending on the geographic plays and well geochemistry. Acceptable fracturing fluid chemistry is a moving target and what is unacceptable today may work well tomorrow depending on the process employed and the technological developments available. The information below presents what is currently acceptable by operators for hydraulic fracturing reuse.

The following specifications for reuse fracturing water in the Marcellus shale were developed with data supplied by Halliburton and XTO Energy:

Parameter	**Maximum**
pH	6.5 to 7.5
TDS	50,000 mg/l
Iron	3.5 mg/l
Hardness	2,500 mg/l as CaCO3
Ca	250 mg/l

Table 17 – Specifications for reuse fracturing water in the Marcellus shale (Tate & Adams, 2010)

Blending has been extensively used in the Marcellus area as shown in Section 3.6. Companies like Range Resources reuse 100% of their flowback and produced water and the main form of treatment they use is blending. Data provided by Range Resources gives another benchmark for reuse specifications:

Parameter	Conventional Limits	Acceptable Blended Marcellus Water	Considerations
pH	6.0 to 8.0	8.1	Fluid Stability, Scaling
Chlorides	< 20,000 mg/l	26,000 mg/l	Fluid Stability
Iron	< 20 mg/l	14.5 mg/l	Fluid Stability
Hardness	*f*(P,T,pH) (+/- 350 mg/l)	Ca^{2+} – 4,200 mg/L, Mg^{2+} – 488 mg/L, Ba^{2+} – 39 mg/L, SO_4^{2-} – 124 mg/L	Scaling
Bacteria Count	< 100/100mL	1 million/100 mL	Bacteria Growth
Suspended solids	< 50 mg/L	1,500 mg/L	Blockages
Oil & Soluble organics	< 25 mg/L	4.6 mg/L	Fluid Stability

Table 18 – Specifications for reuse fracturing water in the Marcellus shale after blending (Gaudlip, 2010)

Based on the above information and the analysis carried out in this Chapter, the reuse limits that will be used in this study will limit the concentrations for TDS, chlorides and hardness ions. The resulting reuse hydraulic fracturing fluid needs to meet these specifications:

TDS < 50,000 mg/l
Chlorides < 26,000 mg/l
Barium < 25 mg/l
Strontium < 25 mg/l

Other hardness ions (e.g. calcium ions) should also be kept at low concentrations but the ions with high precipitation affinity (e.g. barium and strontium) are the ones that need to be tightly controlled.

5. Chapter 5 – Water Treatment Technologies

5.1. Treatment Options

There are several stages of treatment that could be performed to wastewater from hydraulic fracturing operations depending on the constituents one needs to remove. Based on the chemical analysis in Chapter 4, each constituent can have different impacts on the effectiveness of reused wastewater. Certain chemicals are more critical, in terms of limiting the future productivity of the well, and need to be reduced to very low concentrations before reuse.

Treatment options were separated in four categories:

Level 1: Primary Treatment

Clarification only (removal of suspended matter, FOG, iron and microbiological contaminants)

Level 2: Secondary Treatment

Softening and clarification (removal of hardness ions, namely Ba^{2+}, Sr^{2+}, Ca^{2+}, Mg^{2+}, in addition to primary treatment)

Level 3: Tertiary Treatment for reuse

Partial desalination to < 50,000 ppm TDS (in addition to primary and secondary treatments)

Level 4: Tertiary Treatment for surface discharge or beneficial use

Complete desalination to < 500 ppm TDS. This level of treatment is suitable for surface discharge according to the PA DEP effluent standards.

The product quality requirements increase as we progress from Level 1 to Level 4. Contaminants, such as dissolved organics, are not an issue for Level 1 or 2 products, but traces of dissolved organics would cause fouling in Level 3 and 4.

Figure 22 shows the requirements for the product streams from each treatment level:

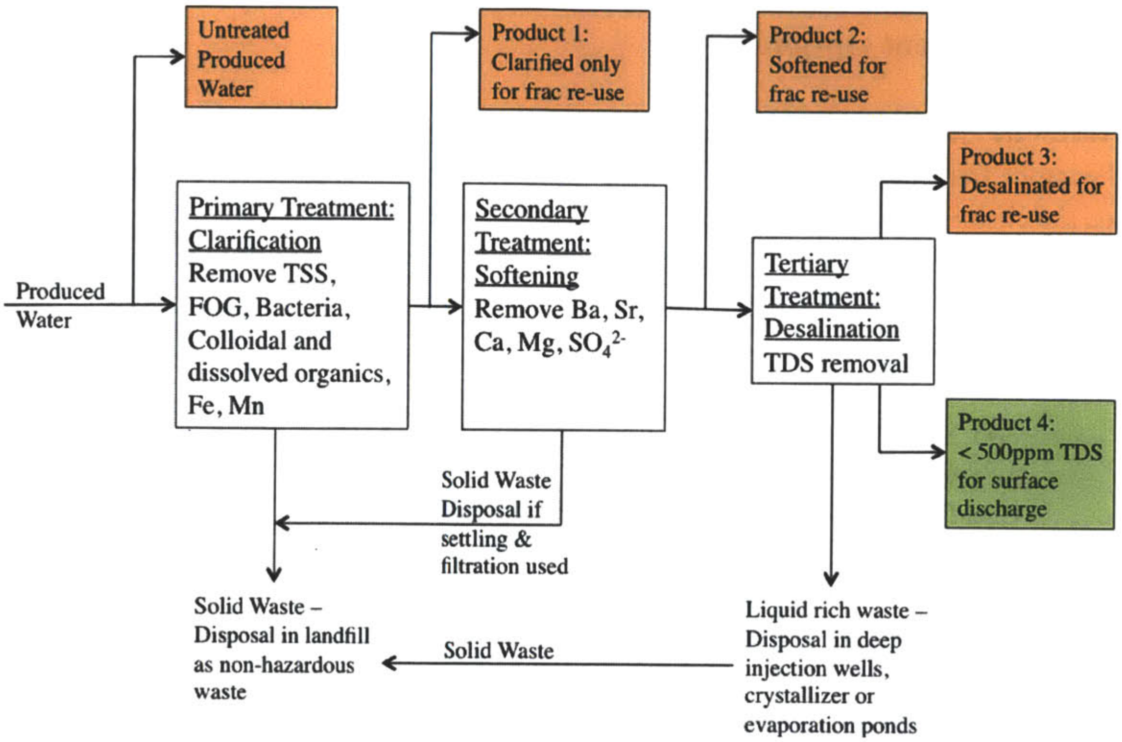


Figure 22 – Schematic illustrating the available water treatment options and the output from every process step.

Indicative compositions for Product 2 and Product 4 are shown in Table 19. The composition analysis was performed on produced water collected 26 days after production by Acharya et al., 2011.

[all units in ppm]	**Untreated flowback water**	**Product 2**	**Product 4**
Barium	30.7	0.147	<0.1
Calcium	1160	37.4	<5.0
Chlorides	21600	21200	243
Iron	184	<0.5	<0.5
Magnesium	1.19	518	8.21
Strontium	152	6.43	<0.1
Sulfates	29	31	<1
Silica (reactive)	48	40	<2
Sodium	16900	17200	16400
TDS	32700	30700	440
TOC	18.4	6	<1
TSS	776	18	<10
Turbidity, NTU	2150	0.63	0.24
pH	7.36	7.54	8.34

Table 19 – Indicative compositions for Product 2 and Product 4 as described in Figure 22

An optimal, but very expensive solution in wastewater treatment would be a zero liquids discharge (ZLD) facility where all the water is recovered and the residue is a valuable by-product salt that is useful as an industrial raw material or as road-salt.

5.2. Technology Options and Their Application to Water Treatment

This section describes the technologies necessary to achieve each treatment level in Figure 22. Information on Figure 23 indicates the effectiveness of each technology in removing certain constituents from the wastewater. Technology options are limited by cost, treatment capabilities, capacity availability, mobility and footprint.

Figure 23 is color coded to indicate the effectiveness of each technology in removing some of the main contaminants in flowback and produced water. Green indicates that the contaminant can be removed without any issues. Yellow indicates that there maybe some risk in damaging the equipment and the contaminant is probably not completely removed. Red indicates that the technology is not efficient in removing specific contaminants and might be irrecoverably damaged. If a box is empty it indicates that a particular technology can not remove that contaminant from the solution.

			TSS and Turbidity reduction	Brine / TDS removal (monovalent)	Ca & Mg Removal - Softening	Ba & Sr Removal - Softening	Sulfate (SO_4^{2-}) removal	Iron (Fe^{2+}), Manganese (Mn^{2+}) removal	Silica (Si) removal	Free Oil & Grease (FOG) reduction	Dissolved organics removal	Bacteria removal
Pre-treatment Technologies	Primary Treatment	Coagulation, Flocculation and simple filtration. Includes aeration & sedimentation.				via sulfate						
		Electro-coagulation (includes separation and clarification)			scale on electrode				dissolved Si		uncertain removal	
		Disinfection (UV, Biocides, Chlorination, Ultrasound)										
		Ultrafiltration / Microfiltration										
		Oil - water separator	small particles									
		Adsorption										
		Ozonation								kinetics; chemicals	foaming	
		Hydrocyclone	small particles									
	Secondary Treatment	Lime softening				if pH=10.3			dissolved Si			
		Ion Exchange			fouling risk		exchanged with Cl-		Si specific resin			
		Activated Carbon								fouling		
Tertiary Treatment Technologies (Desalination)	Membrane Separation	Nanofiltration			fouling	fouling		fouling	fouling			
		Reverse Osmosis			fouling	fouling	fouling	fouling	fouling			
		Forward Osmosis			fouling	fouling	fouling	fouling	fouling			
		Membrane distillation			fouling	fouling	fouling	fouling	fouling			
		Electrodialysis			fouling	fouling		fouling	fouling			
		Electrodialysis reversal (EDR)			fouling	fouling		fouling	fouling			
		Capacitive Deionization			fouling	fouling		fouling	fouling			
	Thermal Technologies	Multi-stage flash										
		Multi-effect distillation										
		Vapor Compression Distillation (VCD)										
	Zero Liquid Discharge	Chemical precipitation / Crystalizer				via sulphate			dissolved Si			
		Evaporator / Concentrator				via sulphate			dissolved Si			

Figure 23 - Technology options for water treatment and expected treatment performance for desired chemicals (Gaudlip et al., 2008; Acharya et al., 2011; RPSEA, 2009)

- **Primary Treatment**
  - Coagulation, Flocculation & Disinfection – Force colloids and other suspended particles in liquid to aggregate forming a floc. Rapid mixing and subsequent settling results in the floc being able to be filtered out. This process includes aeration to oxidize species like iron to a less soluble state.

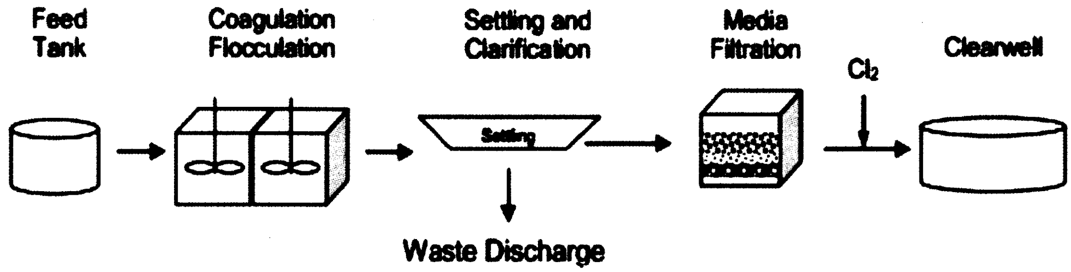


Figure 24 – Illustrative reaction train with unit processes necessary for Coagulation, Flocculation and Disinfection (DOI, 2010)

  - Electro-coagulation – removes contaminants by passing an electrical current through water to induce oxidation and reduction reactions in the water that is being treated. It has low power requirements and no chemical additions.
  - Disinfection – This can be either chlorination or UV based disinfection process.
  - Microfiltration / Ultrafiltration – Low pressure membrane filtration process for removing TSS and colloids.
  - Adsorption – Adsorbents are capable of removing iron, manganese, total organic carbon, BTEX compounds, heavy metals and oil from produced water. Adsorption is generally utilized as a unit process in a treatment train rather than as a stand-alone process.
  - Ozonation – Ozone is a strong oxidizing agent able to degrade organics.
  - Hydrocyclone – separates solids from liquids based on the density of the materials.

- **Secondary Treatment**
  - Lime softening – Hydrated lime ($Ca(OH)_2$) or soda ash (Na_2CO_3) are used to reduce hardness levels (Ca^{2+}, Ba^{2+}, Sr^{2+})

$$Mg(HCO_3)_2 + 2Ca(OH)_2 \rightarrow Mg(OH)_2 + 2CaCO_3 + 2H_2O$$
$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O$$
$$CaCl_2 + Na_2CO_3 \rightarrow 2NaCl + CaCO_3$$

    If hydrated lime is in sufficient quantity to raise the pH to alkaline levels (pH ~10.3) then carbonate hardness and heavy metals like barium and strontium can precipitate (DOI, 2010). Insoluble barium compounds may be formed at low carbonate levels requiring coagulation and flocculation. This is a low capital cost, proven and reliable technology.

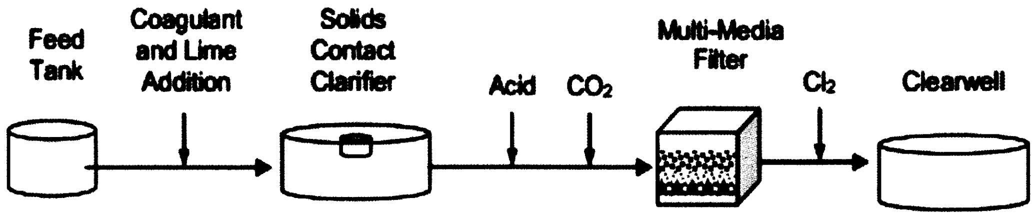


Figure 25 – Illustrative reaction train with unit processes necessary for Lime Softening (DOI, 2010)

- Ion Exchange – Reversible exchange of ions between the liquid and solid resin. Calcium, magnesium, barium, strontium and radium removed by cation exchange resins. Lime softening pretreatment required. This is an effective, mature technology. It requires restocking of salt supply and disposal of concentrate.
- Activated Carbon – A highly adsorbent form of carbon used to remove dissolved organic matter from water

	Basic Separation	**Disinfection**	**Adsorption**	**Advanced Technologies**
Primary Treatment	- Coagulation - Electrocoagulation - Flocculation - Settling - Hydrocyclone	- Chlorination - UV disinfection	- Conventional adsorbents	- Microfiltration - Ultrafiltration
Secondary Treatment	- Lime softening	- Ozonation	- Ion Exchange - Activated Carbon	

Table 20 – Primary and Secondary Treatment Technologies

- **Tertiary Treatment**

Membrane Separation

- Nanofiltration – Medium pressure membrane process for removing di- and tri-valent ions
- Reverse Osmosis (RO) – Method of separating water from dissolved salts by passing feed water through a semi-permeable membrane at a pressure greater than the osmotic pressure. Some of the biggest limitations for RO are costs, pretreatment/feed pump requirements and high potential for fouling.
- Forward Osmosis (FO) – An osmotically driven membrane process, during which water diffuses spontaneously from a stream of low osmotic pressure (feed) to a

hypertonic solution of high osmotic pressure. Unlike RO, the system operates without the need of applying hydraulic pressure.

- Membrane Distillation – involves a thermally driven membrane separation process that utilizes a low-grade heat source to facilitate mass transport through a hydrophobic, micro porous membrane. A hydrophobic membrane displays a barrier for the liquid phase, letting the vapor phase (water vapor) pass through the membrane's pores. The driving force of the pressures is given by a partial vapor pressure difference created from the temperature difference.

Electrically Driven Membrane Separation

- Capacitive Deionization – Ions are adsorbed onto the surface of porous electrodes by applying a low voltage electric field producing deionized water. A modification to the technology is a membrane capacitive deionization where an anion exchange membrane is inserted in front of the anode and a cation exchange membrane is inserted in front of the cathode. In this way, ions of the membrane are inhibited from leaving the electrode region.
- Electrodialysis – use of semi-permeable membranes in which ions migrate through the membrane from a less concentrated to a more concentrated solution as a result of the ions' representative attractions to direct electric current.

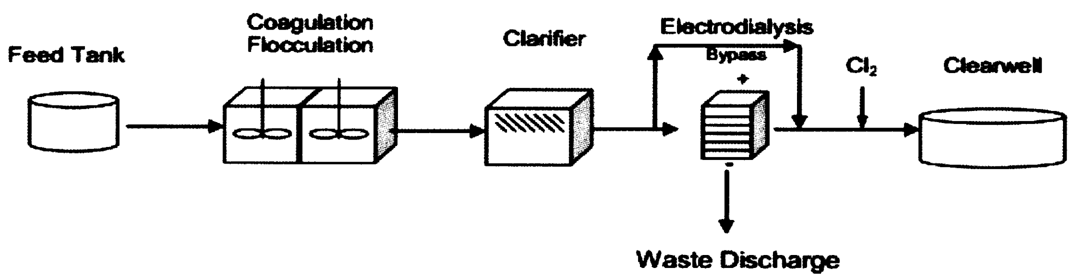


Figure 26 – Illustrative reaction train with unit processes necessary for Electrodialysis (DOI, 2010)

- Electrodialysis Reversal (EDR) – same technology as an electrodialysis device, however, periodically the direction of ion flow is reversed by reversing the polarity applied electric current. Limitations for this technology include high electrical requirements and concentrate disposal.

Thermal Technologies

- Multi effect distillation
- Multi stage flash (MSF)

- Vapor Compression – The are variations to this technology which could include mechanical vapor recompression (MVR) currently used by many water treatment companies

Zero Liquid Discharge

- Crystallization technology
- Evaporator/Concentrator

Desalination Treatment Technologies				
Membrane Separations	**Electrically driven separations**	**Novel membrane processes**	**Thermal technologies**	**Zero Liquid Discharge (ZLD)**
- Nanofiltration - Reverse Osmosis	- Electrodialysis - Electrodialysis Reversal - Capacitive Deionization	- Membrane distillation - Forward Osmosis	- Multi-effect distillation - Multi stage flash - Vapor compression	- Crystallizer - Evaporator / Concentrator

Table 21 – Tertiary (desalination) Treatment Technologies

By far, the most important and costly problem in flowback water treatment is TDS reduction in product water. Current technology options are expensive and prohibit flowback water to be desalinated and recycled on-site. Primary and secondary treatment technologies are used in combination with blending to achieve the necessary composition for reuse.

The variability in the flowback composition across the Marcellus shale makes it hard to select a technology that is appropriate for all well sites. Figure 24 illustrates the TDS concentration for 19 different wells in the Marcellus shale over flowback volume. As expected, the general trend is that as flowback is progressing the TDS concentration increases. However, the trajectories follow very different paths. The differences might be due to the geology in that particular region and/or the fracturing fluid chemistry. Flowback from certain wells does not exceed 40,000ppm which enables treatment with less energy intensive treatment technologies like reverse osmosis. On the other extreme, certain flowback streams are so saline that they cannot be treated with thermal desalination processes and require expensive treatment from membrane distillation and zero liquid discharge technologies.

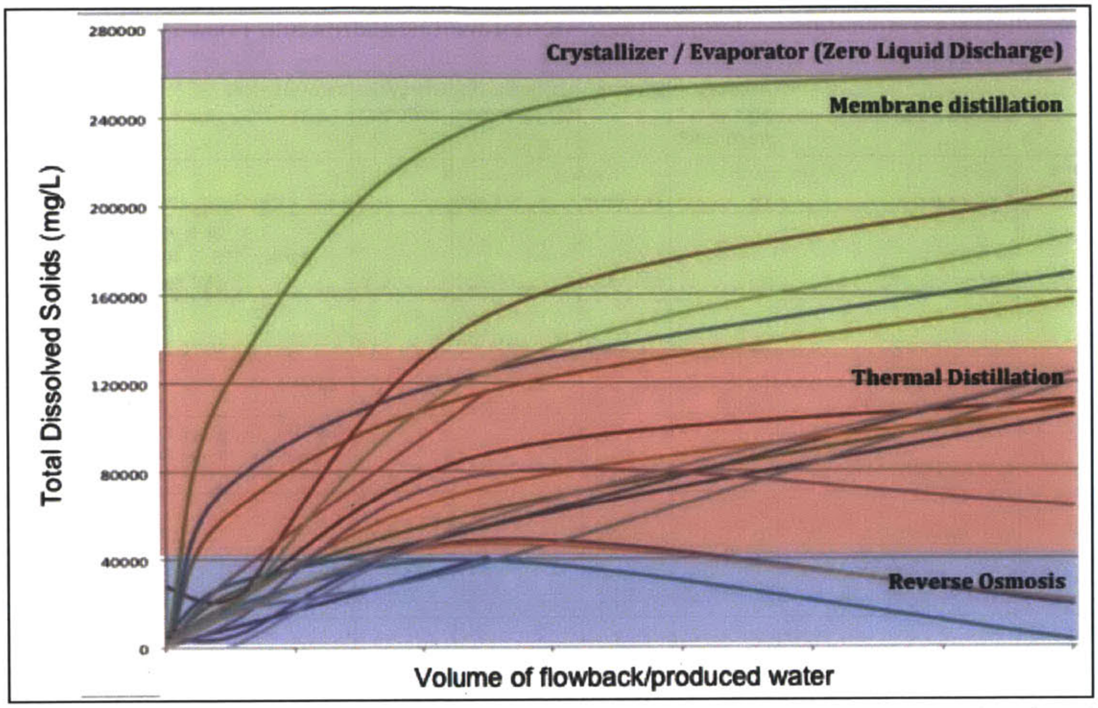


Figure 27 - Time series data for TDS values [mg/L] in the Marcellus shale region for 19 different wells from different locations (Veil, 2012b; Hayes, 2009)

5.3. Current technologies for TDS reduction

Core technologies currently in use for the removal and concentration of dissolved salts vary and depend on the concentration of the total dissolved solids (TDS). For TDS concentrations of up to 20,000 mg/L (occasionally up to 40,000 mg/L in special cases), reverse osmosis has been the preferred method. Thermal distillation is used for waters with TDS concentration of 40,000-100,000 mg/L. New and cost effective technologies that treat wastewaters with TDS exceeding 200,000 mg/L are needed.

Information about these technologies is not widely available and varies considerably among different sources. Particularly data about cost is presented in wide ranges. The cost information shown in Table 22 includes the capital and operational cost for each technology. Cost of treatment is highly dependent on (a) the capacity of the technology unit and (b) the salinity of the wastewater; therefore the cost reported by various sources results in a large ranges.

Details about the desalination technologies that are currently available or currently being developed are shown in Table 22. Desalination technologies that are currently being developed and not yet used at a commercial scale in the Marcellus region include: Electrodialysis, Capacitative Deionization, Membrane distillation and Forward Osmosis.

			Requires pre-treatment?	Lifetime	Maximum TDS Concentration	Energy Use [kWh/bbl]	Recovery rates	LCOE (low) [per bbl]	LCOE (high) [per bbl]
Desalination Treatment Technologies	Membrane Separation	Nanofiltration	Yes	3 - 7 years	20,000	0.08	75-90%		
		Reverse Osmosis	Yes	3 - 7 years	45,000	0.68	TDS: 25k @ 75-90% recovery; TDS: > 40k, 40-65% recovery	$0.42	$3.50
		Forward Osmosis	Yes	3 - 7 years	35,000	0.00	> 96% with RO/FO system		
		Membrane distillation	Minimal	3 - 7 years	250,000	0.65	60-95%		
		Electrodialysis	Yes	4 - 5 years	35,000	0.48	TDS: 35k, 10,000 bpd @ 75% recovery; 90% recovery at low TDS		
		Electrodialysis reversal (EDR)	Yes	4 - 5 years	8,000	0.60	80-90%		
		Capacitive Deionization	Minimal	10 years	6,000	0.76	80%		
	Thermal Technologies	Multi-stage flash	Minimal	30 years	40,000	4.70	10-20%		
		Multi-effect distillation	Minimal	20 years	100,000	1.90	20-67%	$3.00	$5.00
		Vapor Compression Distillation (VCD)	Minimal	20 years	200,000	2.94	TDS: 60-80k @2500bpd, 70-85% recovery;TDS:150k, 50% recovery		
	Zero Liquid Discharge	Chemical precipitation / Crystalizer	Minimal	20 years	650,000	11.5	95% recovery	$6.00	$10.00
		Evaporator / Concentrator	Minimal	20 years	100,000	3.50	98%		

Table 22 – Specifications of Desalination Technologies (RPSEA, 2009; Hamilton Engineering, 2009; Vidic, 2011; Veil & Puder, 2006; Gaudlip et al., 2008; Alleman, 2011; ALL Consulting, 2012; Antero Resources, 2011)

5.3.1. Commercial Treatment Technologies and Companies for TDS reduction

The technologies and companies shown in Table 23 are currently commercialized and operate across the shale plays. All the technologies shown are able to reduce TDS levels however the most effective ones (thermal distillation and crystallization) require a large energy input and are expensive. Reverse osmosis as described above is limited to treating water with less than 40,000ppm TDS. Forward Osmosis has not been adopted at a large scale but has the potential to provide a cost effective solution if issues with scaling and fouling can be resolved.

Thermal Distillation	Fountain Quail (Aquapure); Aquatech; AltelaRain; Intevras; GE Water & Process Tech; Total Separation Solutions; 212 Resources
Reverse Osmosis	Veolia; MI Swaco; Ecosphere; Geopure: GE Water & Power; Intevras; Abtech
Crystallization	Veolia; Intevras; Aquatech; 212 Resources
EDR	GE Power & Water
Forward Osmosis	Oasys Water

Table 23 – Commercial wastewater desalination processes and vendors (ALL Consulting, 2012)

5.3.2. Current Technologies for Primary and Secondary Treatment

Certain novel technologies that can provide water treatment onsite can help water management issues even if they are not able to reduce TDS levels. Removing suspended solids, organics and hardness ions from low TDS water allows companies to blend it with fresh water and reuse it for hydraulic fracturing of subsequent wells.

Technology	Treatment capabilities	Existing companies
Membrane Filtration / Ultrafiltration	Removes hydrocarbons and TSS	Abtech Industries
Absorption	Removes: BTEX, Natural gas, Acetone, Methanol, Non-ionic surfactants	Produced Water Absorbents
Electro-oxidation	Produces chlorine disinfectant to eliminate bacteria	MiOX
UV Light	Removes bacteria	Ecosphere
Ozone	Removes bacteria	Ecosphere
Electro-coagulation	Removes hardness, hydrocarbons and TSS	Baker Hughes; WaterTectonics

Table 24 – Commercial wastewater treatment processes and vendors for primary and secondary treatment

5.4. Water Management Pathways

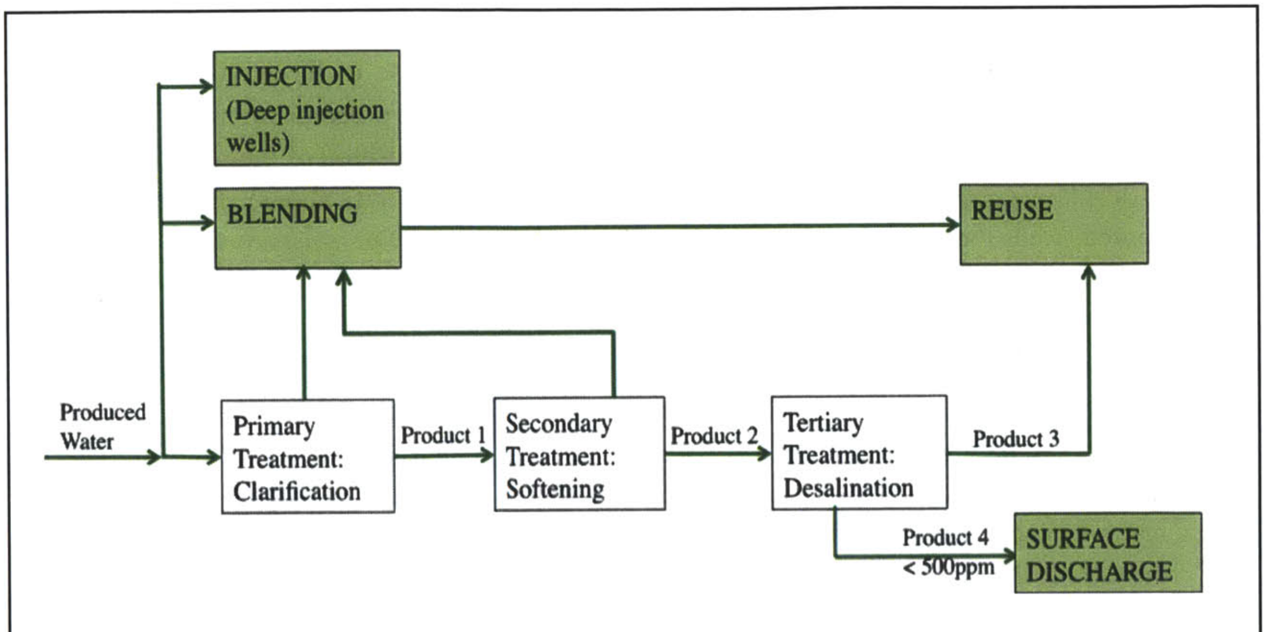
As discussed throughout this document, there are three main options to managing wastewater from shale gas operations:

A) Injection in disposal wells

B) Reuse in hydraulic fracturing operations

C) Surface discharge or beneficial use after treatment

The outputs from primary, secondary and tertiary treatment, shown in Figure 22, as well as the untreated produced water, can be managed in one of the three management options mentioned above. All the possible water management pathways between the three treatment and the three management options were analyzed and are listed in Appendix F. The six most likely water management pathways are identified and shown in Figure 28.



DISPOSAL	Untreated flowback → Disposal well
BLENDING and REUSE	Untreated flowback → Blending → Reuse
PRIMARY TREATMENT, BLENDING and REUSE	Untreated flowback → Primary treatment → Blending → Reuse
PRIMARY + SECONDARY TREATMENT, BLENDING and REUSE	Untreated flowback → Primary treatment → Secondary treatment → Blending → Reuse
TERTIARY TREATMENT and REUSE (onsite)	Untreated flowback → Primary treatment → Secondary treatment → Tertiary treatment (for fracturing reuse) → Reuse
TERTIARY TREATMENT and DISCHARGE (offsite - CWT)	Untreated flowback → Primary treatment → Secondary treatment → Tertiary treatment (for <500ppm product) → Surface discharge or beneficial use

Figure 28 – Most likely water management pathways for wastewater from hydraulic fracturing operations[22]

The six water management pathways identified in Figure 28 are examined in detail in terms of cost and capacity in Chapter 6.

[22] The terminology used is consistent with Chapter 5, and in particular Figure 22

The first pathway, shown in Figure 28, involves the injection of untreated flowback water to disposal wells. There is no treatment involved in that pathway. The second pathway identified is blending of untreated flowback and direct reuse of the resulting fluid in subsequent hydraulic fracturing. This approach is possible if the composition of flowback is such that direct blending and dilution can reduce the composition of the resulting fluid to levels acceptable for reuse (see Section 4.3 for reuse specifications). However, the approach has the risk of affecting fluid stability, due to the TDS concentration, presence of hardness ions and FOG, and can cause blockages in the well due to scaling and increased concentration of TSS. The next two water management pathways identified involve onsite (a) primary and (b) primary and secondary treatment before blending and reuse. Approach (a) removes solids and FOG before reuse while approach (b) also reduces the hardness concentration. This can eliminate some of the problems mentioned above for the pathway using no treatment. The last two water management pathways involve desalination techniques, which means they treat the water by removing most of the salts (TDS, hardness ions, iron and manganese etc.). One of the desalination pathways is for water treatment performed onsite with the objective of reusing the treated water for hydraulic fracturing. In areas with lack of fresh water it is possible that treatment is performed at a CWT facility and water is then returned to the site for reuse. Since water availability in the Marcellus shale region is not an issue this is unlikely. The last desalination pathway is for desalination treatment performed at a Centralized Wastewater Treatment facility with the objective to discharge the treated water to surface waters and possibly use the concentrated brine product for beneficial use, such as road salt.

To summarize, the six water management pathways that will be examined in detail in Chapter 6 are the following:

- Injection to disposal wells
- Blending and reuse of untreated flowback
- Primary treatment, blending and reuse
- Primary and secondary treatment, blending and reuse
- Primary, secondary and tertiary treatment and reuse
- Centralized Wastewater Treatment for surface discharge

6. Chapter 6 – Results and Scenario Analysis

This chapter incorporates information from all the previous chapters to establish cost estimates for the six main water management pathways described in Section 5.4. Case scenarios are analyzed to evaluate how different factors such as trucking costs, distance of treatment options from the well site, availability of disposal options. affect the choice of water management pathways. An analytical decision model is used to analyze the results when multiple factors are varied and understand how the system can react to future changes in regulation and technology developments.

All calculations and assumptions in Chapter 6 are based on assessing flowback water volumes. Flowback water presents the main problem in wastewater management because of the fact that very large volumes are produced during the first two weeks after a well is fractured. Even though the volumes of flowback and produced water are comparable over the lifetime of the well in the Marcellus region (Section 3.4), the first one flows over the period of less than a month while produced water flows over the period of 5 to 6 years. As a result the water management methods for the two flows are significantly different.

6.1. Evaluating Water Management Costs

The six main wastewater management pathways identified in Section 5.4 are analyzed and compared in detail in this section. Figure 25 in the previous chapter summarizes these main water management pathways and all the steps that are involved in water treatment.

The information available in the literature about technology costs is very opaque and does not present a clear picture on what is included in terms of capital and operational expenditure. Furthermore, most reports present the pure technology costs rather than presenting the costs for the entire water management process, which includes water sourcing costs, water transportation costs and blending costs (if necessary). In this thesis, all those factors are taken into account in order to derive cost ranges for the complete water management process. It is important to note that because of the range of costs reported in the literature, from both research and industrial reports, there is a significant amount of uncertainty with regards to actual costs of treatment. Moreover costs are highly depended on the composition of the flowback water, which affects the operational costs (e.g. energy requirement) for particular technologies, and other technology specific characteristics like recovery factors.

The analysis will exclude zero liquid discharge technologies. Crystallization and Evaporation techniques are currently the most expensive techniques available to treat hydraulic fracturing wastewater. After treatment the products are a clean water stream and a solid salt cake that can be disposed as solid waste. These methods are mainly used when wastewater cannot be disposed of properly in a liquid form. They are currently used in the industry but for the purposes of this thesis we will only investigate wastewater disposal and treatment methods that do not involve solid waste disposal.

This chapter will proceed by describing and quantifying all the cost components that are included in the cost calculations. The cost ranges for all the water management pathways are presented and analyzed in the following sections. In extension a sensitivity analysis is used to investigate the effect of trucking distances, trucking costs and drilling patterns on the total costs. Lastly, a water management decision model is presented that allows us to investigate how the water management system can adapt over time to adjust to cost changes and regulatory changes in this sector.

This section describes and quantifies all the elements that are included in the cost calculations for the water management pathways.

Treatment costs

Technology costs were synthesized from a variety of data sources (both academic and industrial reports) with a subset of the data shown in Table 22. There is understandably large variability in the reported technology costs and so the costs were aggregated to represent the treatment costs for the water management pathways shown in Figure 28. The upper and lower estimates for the treatment costs are shown in Table 25.

	Lower estimate of treatment cost [per bbl]	Upper estimate of treatment cost [per bbl]
Primary treatment	$1.50	$2.50
Primary and Secondary treatment	$2.50	$4.00
Primary, Secondary and Tertiary treatment (onsite)	$5.50	$8.00
CWT Tertiary treatment (<500ppm product)	$2.75	$5.00

Table 25 – Upper and Lower bound treatment costs for water management pathways (Sources: Veil & Puder, 2006; Acharya et al., 2011; Antero Resources, 2011; RPSEA, 2011; ALL Consulting, 2012; Vidic, 2011; Veil & Argonne, 2010)

Recovery factors and Concentrate disposal

Treatment technologies produce a certain volume of concentrated brine water that requires disposal to landfill facilities. The transportation cost for concentrated brine affects the overall cost of the water management pathway. The volume of concentrate depends on the technology's recovery factor. Recovery factor is the ratio of the output of treated water over the input volume of wastewater into the technology. The recovery factors used in this analysis are shown in Table 26:

	Technological TDS limit	Recovery factor
Primary Treatment (Filtration and FOG removal)	n/a	100%
Secondary Treatment (Lime softening)	n/a	98%
Tertiary Treatment (Thermal Distillation / Mechanical Vapor Compression (MVC))	100,000[23]	70%

Table 26 – Approximate recovery factors for water treatment technologies (ALL Consulting, 2012; Alleman, 2011; RPSEA, 2009; Kuijvenhoven, 2011)

[23] Thermal distillation / Vapor compression distillation (VCD) can operate at higher level of TDS, however it would achieve a lower recovery factor and would result in a higher cost due to energy requirements.

Recovery factors depend on the composition of the feed water therefore exact values cannot be identified. The values presented in Table 26 are average values based on various sources.

Fresh water sourcing and transportation

Water can be sourced directly from a river after acquiring specific environmental permits. Alternatively water could also be sourced from municipalities. Capital cost necessary to withdraw water from surface waters, like a river, should be included in the water management calculations. The estimated cost for fresh water from the river used in this analysis is $0.05/bbl (Acharya, 2011). In the Pennsylvania region, there is no shortage of water supply and most oil and gas operators source their water from nearby rivers. For the purposes of this study an average distance of 10 miles was assumed between the well site and the fresh water source. The trucking costs of the fresh water from the source to the well site were included in the calculation. Operators with large activity in the Marcellus area occasionally build temporary pipelines to transfer this water. The temporary pipeline option was not included in the calculations.

Trucking

Water transportation is a major cost component of the total cost for certain water management methods. This will be discussed in detail in the results section. The trucking cost assumptions used in this thesis are outlined below:

Truck capacity: 115 bbls per truck (Acharya, 2011)

Average speed: 45 miles per hour

Cost: $85-175 per hour per truck (Scorpion E&P Inc, 2012; Veil & Puder, 2006)

This results to approximately $0.02-0.03 per bbl per mile for operational cost. The amortized cost of buying a truck for $87,500 (Central Truck Sales, 2012) with an amortization period of 5 years is approximately $0.20 per bbl[24]. If 3 years amortization period is used, the cost is approximately $0.40 per bbl.

Disposal injection wells

Produced water injection costs range from $0.70/bbl to $10/bbl. In most cases the cost is approximately $1/bbl and there are very few disposal wells that charge more than $3/bbl (Veil & Puder, 2006).

[24] Calculated based on a 4800 gallon tank (115 bbl) at $87,500 assuming that an average truck performs 2 roundtrips per day and operates for 335 days per year.

Centralized Wastewater Treatment (CWT)

CWTs vary in costs depending on the services they provide and the type of technology they use (Reverse osmosis; Thermal distillation; Dilution; Lime softening etc.). According to a variety of sources costs may vary from \$2.75/bbl up to \$5/bbl (Veil & Puder, 2006; Veil & Argonne, 2010; Vidic, 2011). New CWTs currently being built that will be compliant with the new PA DEP discharge limits (Section 2.4.6) are expected to be at the upper end of this range if not higher.

Blending costs

Costs for blending are expected to include handling costs for water tanks and equipment maintenance. Costs are approximately \$0.50/bbl to \$1.50/bbl (Antero Resources, 2011).

Blending and Make- up water requirements

In the Marcellus shale, the flowback that returns to the surface for treatment is about 15% of the fracturing fluid that was injected into the well for hydraulic fracturing. For that reason blending untreated flowback water requires an additional 85% make-up water to have a complete batch of fracturing fluid of about 5.7M gallons.

For any water management pathway that requires blending we need to calculate how much make-up water is necessary in order to ensure that the resulting fluid meets the re-fracturing specifications (Section 4.3) issued by Marcellus operators (TDS concentration < 50,000ppm; Chlorides concentration < 26,000ppm). Furthermore, as shown in Table 26, for the method that requires onsite tertiary treatment the feed water needs to be blended down to 100,000ppm TDS before treatment in thermal distillation or vapor compression distillation (VCD) processes can take place.

The Department of Energy (DOE) Water Mixing and Scale Affinity Model (DOE & ALL Consulting, 2012) was used to determine the make-up water requirements for blending. The composition of a typical Marcellus flowback stream was used (TDS concentration = 124,000ppm; Chlorides concentration = 79,000ppm - see Appendix G for details) to determine blending requirements. This calculation should be considered with caution since composition of flowback streams from the Marcellus shale varies significantly and may have considerably greater or lower TDS and chlorides concentration than the one used in this analysis. This could have an effect both on the economics and the technical viability of blending methods. For the make-up water both fresh water (municipal water supply) and lake withdrawal water compositions were considered when carrying out this calculation. The results for fresh make-up water are shown in Table 27.

Untreated flowback blended for reuse	Fresh water used TDS Chlorides	85% 20,510 ppm 13,839 ppm	Limits for water reuse TDS < 50000ppm Cl < 26000ppm
Flowback blended for reuse after primary and secondary treatment	Fresh water required TDS Chlorides	65% 45,330 ppm 25,314 ppm	Limits for water reuse TDS < 50000ppm Cl < 26000ppm
Flowback blended before tertiary treatment	Fresh water required TDS Chlorides	20% 95,770 ppm 66,875 ppm	Limits for distillation TDS < 100000ppm

Table 27 – Blending requirements for three wastewater treatment pathways: (a) Blending and reuse; (b) Primary and Secondary treatment, blending and reuse; (c) Blending prior to tertiary treatment.

Blending of untreated flowback water with 85% make-up water results in a product that is within the re-fracturing specifications indicated in Section 4.3. This is expected to be the cheapest wastewater management pathway. Blending after primary and secondary treatment requires 65% make-up water in order to reduce the TDS and chlorides concentration to the required levels. Lastly, 20% make-up water is required in order to reduce the TDS concentration of flowback water below 100,000 so that it can be treated cost effectively by a desalination technology. See Appendix G for the composition and scale calculations of all the feed streams, as well as the detailed blending results for some of the treatment processes shown in Table 27.

Taking into account both the blending requirements (Table 27) and the technology recovery factors (Table 26) here are the make-up water requirements that will be necessary by each water management method:

	Make-up water requirement (approximate)
Disposal	100%
Blending and Reuse of untreated flowback	85%
Primary treatment, blending and reuse	65%
Primary and Secondary treatment, blending and reuse	65%
Tertiary treatment and reuse (onsite)	29%[25]
Tertiary treatment and reuse (CWT)	100%

Table 28 – Make-up water requirements for all water management methods

[25] Accounts for the fact that tertiary treatment technologies have approximately a 70% recovery factor

6.2. Results - Water Treatment Pathways Costs

All the cost components analyzed in the previous section were used to calculate the cost of water treatment pathways.

The assumptions used in the cost calculations are listed below:

- Average volume of fracturing fluid = 5.7M gallons
- 15% of fracturing fluid returns to the surface as flowback
- Distance from well site to UIC disposal well = 100 miles
- Distance from well site to CWT facility = 40 miles
- Distance from well site to fresh water supply = 10 miles
- Economies of scale based on capacity have not been included

The following equation was used to calculate the cost of each treatment pathway:

$$C_{Total}=C_{Treatment}+C_{Concentrate\ disposal}+C_{Untreated\ water\ disposal}+C_{Fresh\ Water}$$

Units: $/bbl feed[26]

Costing for the complete water management process includes the cost for sourcing fresh water ($C_{Fresh\ Water}$) for the next fracturing job. This includes fresh water required for a complete fresh water fracturing job, make-up water required for blending and cost of transportation of the fresh water to the well site. Disposal costs for both untreated water ($C_{Untreated\ water\ disposal}$) and concentrate disposal ($C_{Concentrate\ disposal}$) are accounted for in the total cost for treatment. $C_{Treatment}$ are the treatment costs shown in Table 25 for all the main water management pathways. High and low estimates are available for the treatment costs therefore the analysis is carried out for upper and lower cost of water management pathways. The detailed cost values are shown in Tables 29 and 30[27].

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[26] Feed in this case is the volume of incoming flowback water

[27] Values in Tables 29 and 30 are rounded to the nearest $0.1, therefore some rounding errors might occur

		Wastewater hauling costs			Fresh water sourcing and hauling costs				
Units: $/bbl of flowback	Technology cost (Opex and Capex)	Trucking untreated wastewater to disposal well	Trucking untreated wastewater to CWT	Trucking concentrate waste to disposal well	Water sourced from fresh water supply for subsequent fracturing	Cost of fresh water	Trucking fresh water to well site	Sourcing water and hauling cost	**Total cost**
Disposal	$0.70	$1.90	$0	$0	100%	$0.30	$2.60	$4.80	**$5.50**
Blending and Reuse	$0.50	$0	$0	$0	85%	$0.30	$2.20	$2.50	**$3.00**
Primary treatment, blending and reuse	$2.00	$0	$0	$0	65%	$0.20	$1.70	$1.90	**$3.90**
Primary and secondary treatment, blending and reuse	$3.00	$0	$0	$0.05	65%	$0.20	$1.70	$1.95	**$5.00**
Tertiary treatment and reuse (onsite thermal treatment)	$5.50	$0	$0	$0.80	29%	$0.10	$0.70	$1.60	**$7.10**
Tertiary treatment and reuse (CWT)	$2.75	$0	$0.90	$0	100%	$0.30	$2.60	$3.80	**$6.60**

Table 29 – Wastewater Management Pathway Costs (low cost estimates)

		Wastewater hauling costs			Fresh water sourcing and hauling costs				
Units: $/bbl of flowback	Technology cost (Opex and Capex)	Trucking untreated wastewater to disposal well	Trucking untreated wastewater to CWT	Trucking concentrate waste to disposal well	Water sourced from fresh water supply for subsequent fracturing	Cost of fresh water	Trucking fresh water to well site	Sourcing water and hauling cost	**Total cost**
Disposal	$3.00	$1.90	$0	100%	$0.30	$2.60	$4.80	$4.80	**$7.80**
Blending and Reuse	$1.50	$0	$0	85%	$0.30	$2.20	$2.50	$2.50	**$4.00**
Primary treatment, blending and reuse	$4.00	$0	$0	65%	$0.20	$1.70	$1.90	$1.90	**$5.90**
Primary and secondary treatment, blending and reuse	$5.50	$0	$0.05	65%	$0.20	$1.70	$2.00	$1.95	**$7.50**
Tertiary treatment and reuse (onsite thermal treatment)	$8.00	$0	$0.80	29%	$0.10	$0.70	$1.60	$1.60	**$9.60**
Tertiary treatment and reuse (CWT)	$5.00	$0.90	$0	100%	$0.30	$2.60	$3.80	$3.80	**$8.80**

Table 30 – Wastewater Management Pathway Costs (high cost estimates)

Figure 29 displays the results from the cost calculations. As expected blending and reuse without any treatment has proven to be the cheapest method of water management. As we analyzed in Section 5, this approach is risky since, if not diluted to low enough concentrations, chemical contaminants (such as Ba, Ca, Sr etc.) and bacteria can cause problems for subsequent fracturing operations. Flowback water in certain regions in the Marcellus is relatively "clean" (less than 40,000 TDS concentration – see Figure 27) which would make this method possible.

Disposal to injection wells covers a wide range of cost values and depending on the disposal fees could be cost competitive against primary (and secondary) treatment with blending. On the other hand, depending on disposal fees, injection at disposal wells could be more costly than disposal at centralized treatment facilities. In Section 3.6, it was shown that flowback from the Marcellus shale is not actually being injected in disposal wells. Only produced water is sent to disposal wells and flowback water is mainly managed through blending processes and CWT facilities. The results below reinforce that statement by indicating how the costs for these options could be comparable, with the main deciding factor being the disposal fees for disposal wells and the distance between the well site and these facilities.

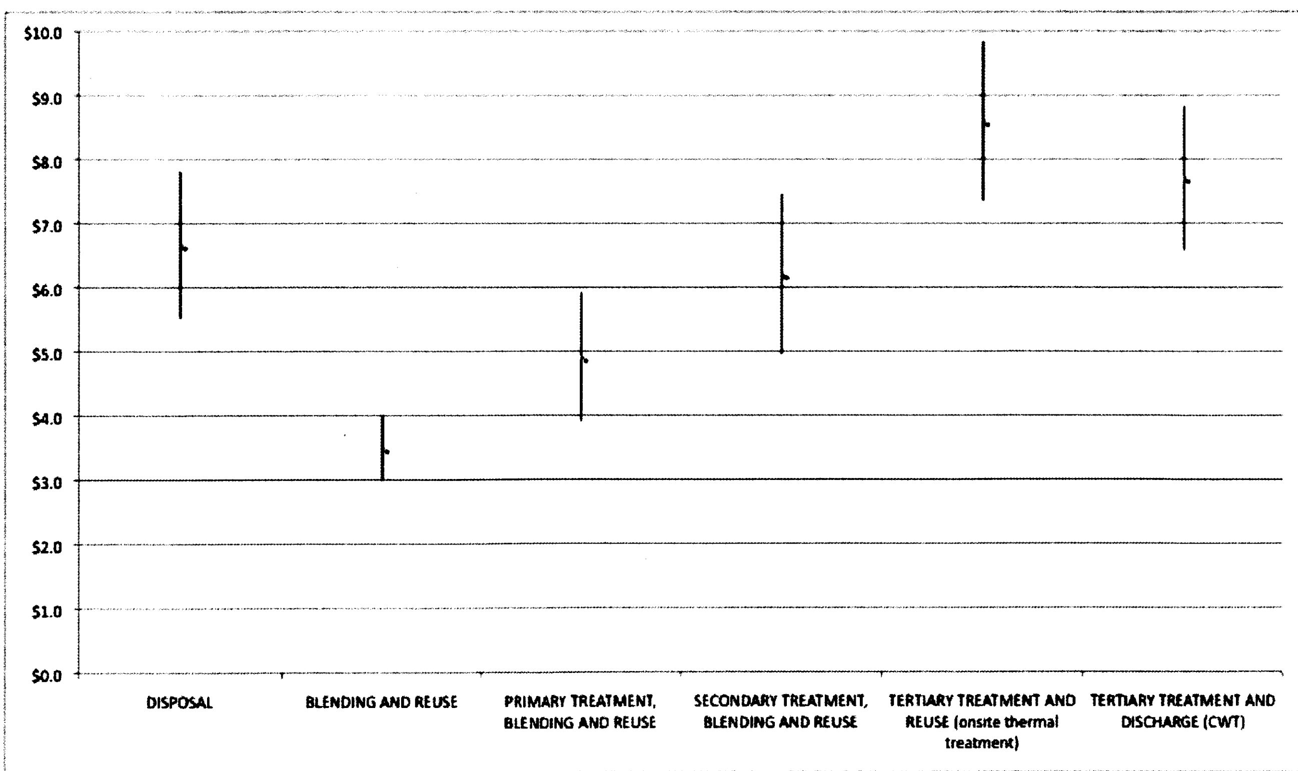

Figure 29 – Cost results for Wastewater Treatment Pathways - includes fresh water costs for subsequent hydraulic fracturing operations. Units: $/bbl of flowback

Tertiary treatment onsite has the highest cost as shown in Figure 29. Certain operators have been using desalination treatment onsite to treat shale gas wastewater but it is likely that the motivation was for experimental treatment and public relations, rather than for an economic driver.

Trucking costs for hauling water, either fresh water to the well site or wastewater removal from the well site, is a large component of the overall costs. Table 31 shows the percentage of costs that is attributed to trucking for all the water management pathways.

	Percentage of cost attributed to trucking (based on low treatment cost estimates)	**Percentage of cost attributed to trucking (based on high treatment cost estimates)**
Disposal	81%	57%
Blending and Reuse of untreated flowback	74%	55%
Primary treatment, blending and reuse	43%	29%
Primary and Secondary treatment, blending and reuse	35%	23%
Tertiary treatment and reuse (onsite)	21%	15%
Tertiary treatment and reuse (CWT)	53%	40%

Table 31 – Fraction of cost attributed to trucking water for all the water management pathways

The analysis was repeated to calculate the cost for the water management pathways without including the cost for sourcing and transporting fresh water. Significant differences were observed between the two approaches and are analyzed below. The results are shown in Table 32 and Figure 30.

The equation used was the following:

$$C_{\text{Total}} = C_{\text{Treatment}} + C_{\text{Concentrate disposal}} + C_{\text{Untreated water disposal}}$$

Units: \$/bbl feed[28]

[28] Feed in this case is the volume of incoming flowback water

	Low cost estimate [$ per bbl of flowback]	High cost estimate [$ per bbl of flowback]
Disposal	$2.6	$4.9
Blending and Reuse of untreated flowback	$0.5	$1.5
Primary treatment, blending and reuse	$2.0	$4.0
Primary and Secondary treatment, blending and reuse	$3.0	$5.5
Tertiary treatment and reuse (onsite thermal treatment)	$6.3	$8.8
Tertiary treatment and reuse (CWT)	$3.6	$5.9

Table 32 – Cost range for wastewater treatment pathways excluding the cost of sourcing and hauling water for subsequent hydraulic fracturing operations

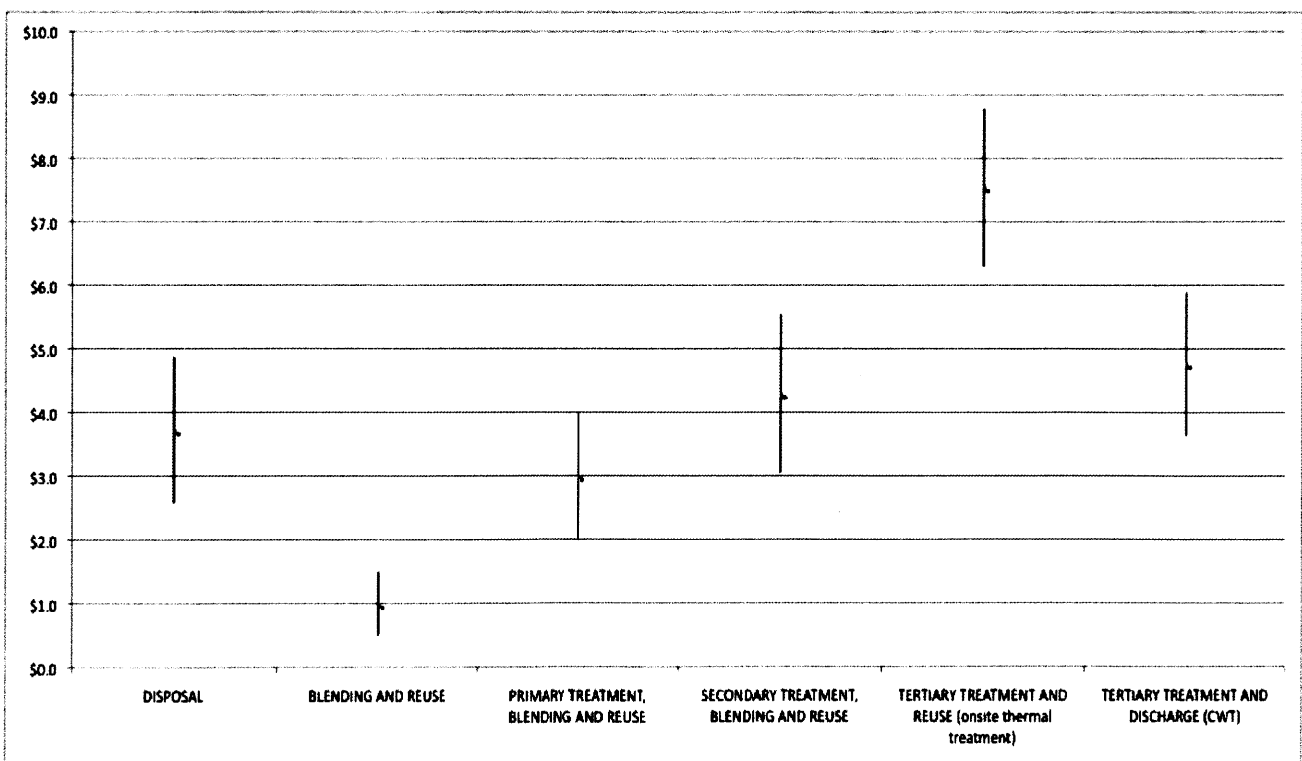

Figure 30 – Cost results for Wastewater Treatment Pathways - excludes fresh water costs for subsequent hydraulic fracturing operations. Units: $/bbl of flowback

The options most heavily affected by excluding fresh water costs are the disposal options (injection wells and CWT). These options do not reuse any water onsite therefore in the previous calculations these options were heavily penalized. The disposal to injection wells becomes considerably more attractive, especially given the fact that there is no technology risk involved with that method of disposal.

The large difference in costs indicates that water sourcing is an important factor when deciding the appropriate wastewater management method and could affect the final treatment decision.

6.3. Scenario Analysis

Scenario analysis is used to investigate the effect of trucking distances, trucking costs and drilling patterns on the total cost and viability of water management options. In this section we attempt to present trends on how several factors can affect the choice of water management systems. Given the uncertainty that governs the assumptions about costs, more emphasis is given on understanding the general trends and identifying the important variables that affect choices in this sector rather than deriving exact values and costs for the scenarios presented below.

6.3.1. Distance away from Disposal wells and CWT Facilities

The distance between the well site and the disposal well can have a big effect on the choice of a water management pathway. Figure 31, indicates how costs vary for the disposal well option with increasing distance. Given our assumptions, if the disposal well is further than 100 miles away from the well site then certain reuse options (like secondary treatment and blending) become economically competitive. At that point, operators would probably be willing to invest in onsite primary and/or secondary treatment and blending facilities, assuming the flowback composition allows them to reach the required fracturing fluid composition after blending. Furthermore, at distances further than 170 miles, the cost of sending the water to a centralized treatment facility becomes cheaper than the option of injection of wastewater in disposal wells. This is supported by current operations in the Marcellus who are currently sending significant volumes of water to CWTs rather than disposal wells. Data from the PA DEP supports that operators are sending 61% of the total produced and flowback water to CWT facilities and only 8% is sent to disposal wells (PA DEP, 2011a). Based on the geographical analysis shown in Appendix H, distances of 170 miles or greater between the well sites and disposal wells are common, especially with the large developments in natural gas drilling in eastern Pennsylvania (refer to Appendix H for more details).

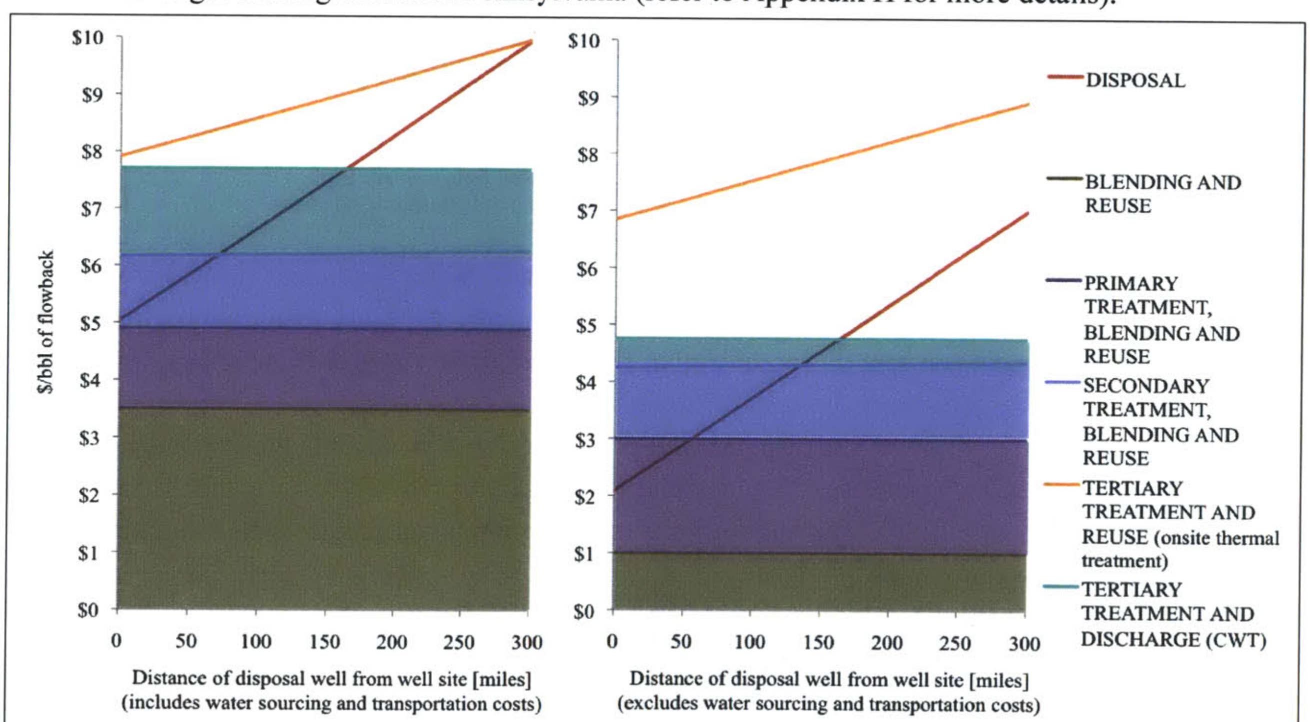

Figure 31 – Effect of the distance of a disposal injection well from the well site to the cost of wastewater treatment methods. All other assumptions from Section 6.2 remain constant (CWT at 40 miles; Fresh water at 10 miles).

Figure 32, illustrates that the distance between the well site and the centralized wastewater treatment (CWT) facility does not have a big effect on the choice of a water management pathway. Whether we are accounting for the cost of sourcing fresh water or not, the distance of the CWT from the well site does not affect the choice of water management pathway within the limits of 0 to 80 miles.

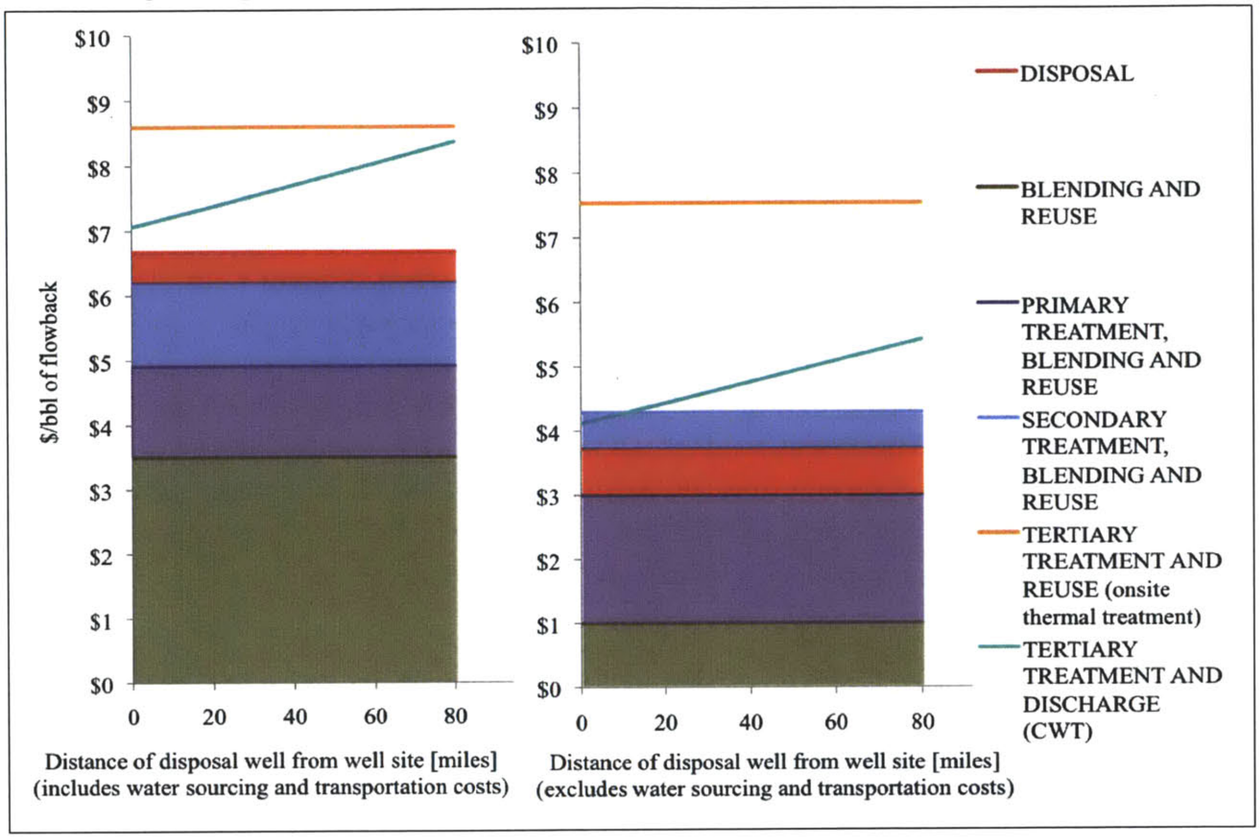

Figure 32 – Effect of the distance of a Centralized Wastewater Treatment (CWT) from the well site to the cost of wastewater treatment methods. All other assumptions from Section 6.2 remain constant (Disposal well at 100 miles; Fresh water at 10 miles)

In conclusion, proximity to the disposal well plays a decisive role on whether an operator will choose to use disposal or CWT as a water management method. On the other hand, distance between the CWT and the well site is not an important factor when evaluating water management options.

6.3.2. Effect of distance from fresh water source

The distance between the well site and the fresh water source affects all wastewater treatment methods. The fresh water source, whether that originates from a river, lake or municipal water plant, is located close to the well site and is not expected to be more than

30 miles away. At this range of distances, the fresh water source location does not have a big effect on the water management pathway chosen, as shown in Figure 33. If the fresh water source is further than 25 miles away, it is possible that onsite tertiary treatment facilities might be more economical than a CWT, however other management options like disposal or blending and reuse are far cheaper and would likely be preferred over onsite tertiary treatment.

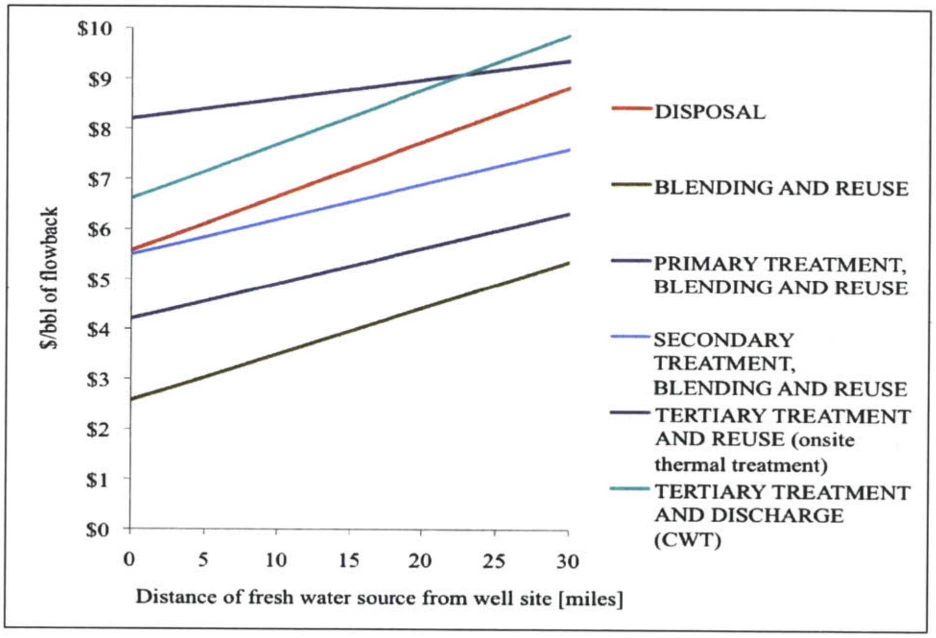

Figure 33 – Effect of the distance of a fresh water source from the well site on the cost of wastewater treatment methods. All other assumptions from Section 6.2 remain constant (Disposal well at 100 miles; CWT at 40 miles). The above data includes the cost of sourcing water. Units for x-axis: miles.

6.3.3. Effect of trucking costs

As discussed above, distances between different treatment facilities and subsequently total trucking costs can significantly affect the choice of wastewater management pathway. For that reason, the cost values allocated to trucking water, whether that's fresh water or wastewater, are extremely important. Figure 34, indicates how variations in the operational and capital costs of trucking can affect the cost competitiveness of different options. As expected, trucking costs only have an appreciable effect if water sourcing and transportation costs are included in the analysis. Within the reasonable cost ranges presented in Figure 34, operational costs have a bigger effect than capital costs. Reported leasing rates for trucking in the Marcellus region currently range between $0.015 to $0.035 per bbl per mile. Based on our current assumptions, at this range, there is no significant effect on the wastewater management pathway chosen. However, any subsequent increase in the operational trucking costs, which is likely to occur due to the increased demand for hauling services in the Marcellus, can significantly affect the cost effectiveness of different management options. Sufficient increases in operational cost, can result in onsite treatment services being preferred over disposal wells or CWT.

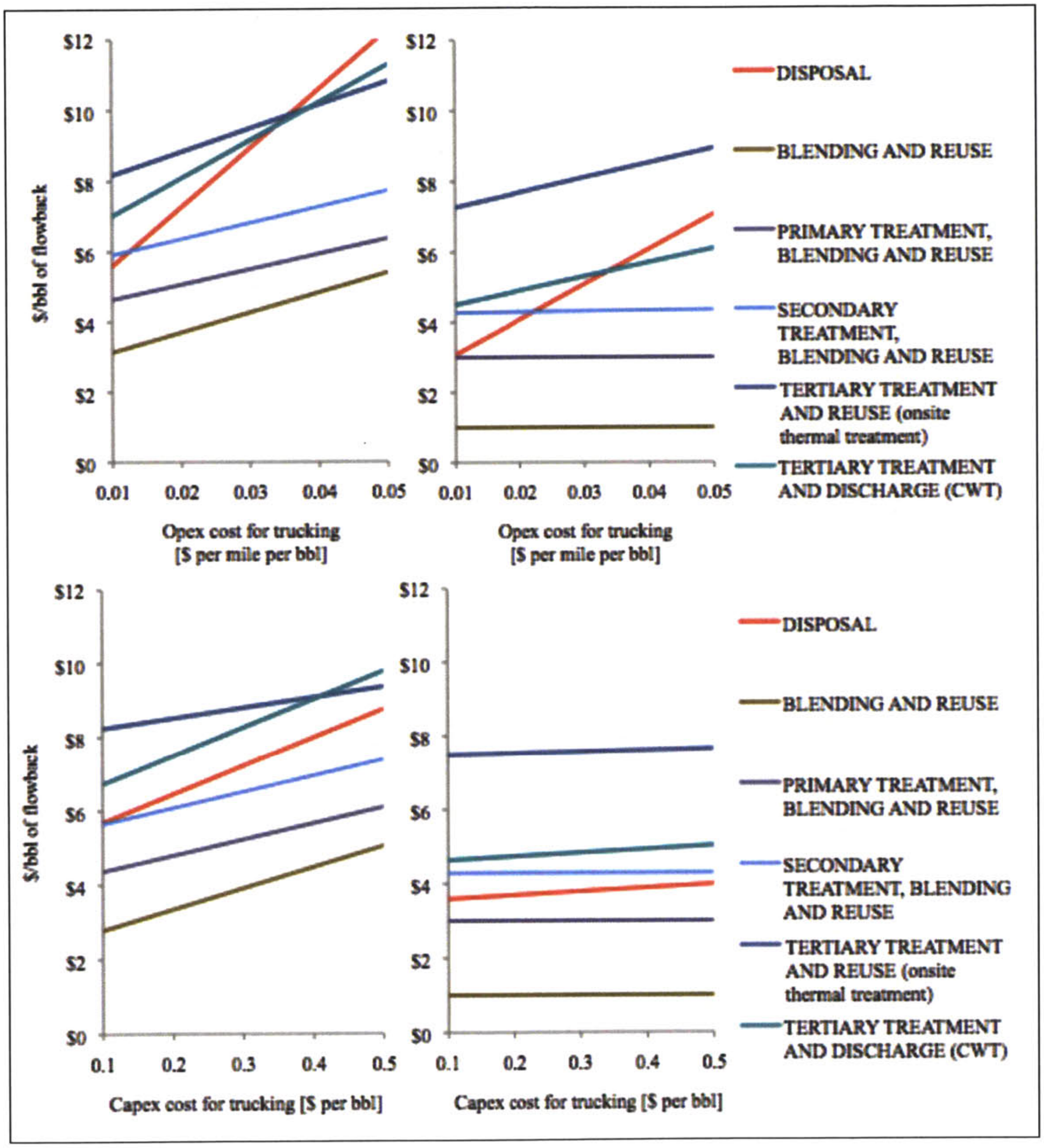

Figure 34 – Effect of capital and operational trucking costs to the cost of wastewater treatment methods. All other assumptions from Section 6.2 remain constant (Disposal well at 100 miles; CWT at 40 miles; Fresh water at 10 miles). Left: Including water sourcing costs; Right: Excluding water sourcing costs

6.3.4. Elimination of disposal options and decreased natural gas drilling trends

Currently, almost all of the flowback and produced water from Pennsylvania operators that requires injection in disposal wells is sent to Ohio (see Section 3.6). Over the past two years, the price of natural gas has been dropping. At natural gas prices less than \$3/mcf, interest in natural gas production has been decreasing and the economic attractiveness of oil exploration is increasing. This statement is supported by the recent developments in Utica shale. Utica shale is an oil rich shale formation located primarily across Pennsylvania and Ohio, and geologically located under the Marcellus shale formation. Utica shale has seen tremendous growth during 2011 when Ohio drilling permits reached record highs (Gerino, 2012). As oil shale developments in Ohio continue to increase, it is likely that Ohio producers will get even more preferential treatment in using disposal wells located in their state. In 2010, Governor Strickland passed the Senate Bill 165, which provided the first revision to Ohio Oil and Gas law in 25 years. As a result there was a differential disposal fee charged to wastewater originating form in-district wells (\$0.05/bbl) and out-of-district wells (\$0.20/bbl), like Pennsylvania (Marcellus) wells (OLSC, 2010). It is possible that these disposal fees for out-of-district producers can increase or Ohio might propose quota restrictions on Pennsylvania producers, making injection disposal a less attractive option for Marcellus producers. In the extreme scenario where injection disposal in Ohio becomes cost prohibitive, operators will need to seek different options for water disposal increasing the urgency for developing sustainable water treatment options.

Lower natural gas prices are also likely to result in lower drilling activity in Marcellus shale over the next few years. If the rate of drilling new wells decreases in the Marcellus there will be lower need for reusing flowback water. Given that federal law prohibits the discharge of waste fluids from onshore oil and gas wells there is no incentive for treatment to be performed at the well site, unless the treated water will be reused. Therefore a decrease in drilling rates will lead to the operators being left with two options: Injection in disposal wells OR treatment of water at Centralized Wastewater Treatment (CWT) plants for surface discharge or beneficial use. Without sufficient centralized treatment capacity and with the possibility of disposal well restrictions, the operators in the Marcellus region can be faced with very expensive water management options.

6.3.5. Comparison between Onsite Vs Centralized Treatment Facilities – Allowing surface discharge

Currently federal law prohibits the discharge of waste fluids from onshore oil and gas wells even if the water is treated to the required effluent limit standards (Section 2.4.6). Assuming this provision would be modified to allow surface treatment, if water were treated onsite to the required standards, it could increase the cost competitiveness of onsite treatment options against centralized treatment options.

The main expense that would be saved if onsite treatment units were allowed to perform surface discharge would be the hauling cost of wastewater to a CWT facility. The effect of trucking untreated wastewater to the CWT could be relatively small since usually CWTs are located close to production wells. Based on our current assumptions, the CWT would have to be located more than 200 miles away from the well site in order for a tertiary on-site treatment facility that discharges all the treated water to be economical. It is highly unlikely that a CWT will not be located within approximately 200 miles from the well site, therefore without any water reuse, onsite treatment is not a viable option. Even with complete water reuse, and based on our current assumptions, the CWT would have to be about 100 miles away in order for onsite tertiary treatment to become economically attractive compared to a CWT facility.

Exploring the possibility for partial reuse of the flowback water can increase the cost competitiveness of the onsite tertiary treatment option, since that limits the amount of fresh water that needs to be trucked to the well site. Keeping in line with the assumption that a CWT facility is located on average about 40 miles from the well site, one can calculate at what treatment cost onsite tertiary treatment will be economical. The treatment cost refers to the cost for the treatment technology alone (i.e. it does not include trucking or buying fresh water). This calculation is based on a CWT treatment cost of \$3.9/bbl[29]. If there is no water reuse, the tertiary treatment technology cost should be less than or equal \$4/bbl in order to be cost equivalent with the CWT option. The slightly higher allowable cost for the onsite technology compared to the CWT is due to the cost savings from discharging water onsite rather than hauling it to a CWT facility. If there is 100% reuse of wastewater, the onsite technology should cost \$6.2/bbl or less in order to be cost competitive with the CWT facility under the stated assumptions. The current costs for tertiary treatment technology onsite range from \$5.50 to \$8 per bbl. Given our assumptions, significant innovation is necessary if onsite treatment will be cost competitive against CWT at low levels of water reuse. The current technology costs make

[29] \$3.9/bbl is the average cost between the CWT cost range of \$2.75 - \$5 per bbl

it uneconomic to use tertiary treatment technology onsite unless there is significant water reuse. The above conclusions indicate a trend but do not allow us to identify the volume of water reuse necessary to render onsite tertiary treatment economical against a CWT facility.

To summarize, onsite treatment facilities do not present an economically viable option unless they perform at least partial water reuse. Allowing surface discharge from onsite treatment facilities will probably not present better water management opportunities unless the technology costs for onsite tertiary treatment are significantly reduced.

6.4. The Water Management Decision Model

The discussion in Section 6.3 has been analyzing each variable affecting the wastewater management system individually and did not account for changes to the system over time. Selecting wastewater treatment options is a multi-variable issue. Factors that can affect decisions in water management include, among others, technology costs, technology performance metrics, proximity to disposal wells and CWT facilities, capacity of disposal and treatment options, potential for reuse.

An analytic decision model was developed to include some of these variables and investigate their inter-related outcomes over time. The optimization method used is a mixed integer linear programming (MILP) model. The objective function is to minimize the cost of water management while making decisions for multiple time periods. A penalty cost is used for any water that remains untreated due to capacity constraints. A discount rate is included to properly account for costs incurred in later time periods.

The outputs of the model are (a) how many new units of a given water management option are necessary at a given time, and (b) how much water is managed by each water management option at a given time. Calculating the number of new units required meant that the model had to be specified as a mixed integer LP model. The advantage is that it gives the capability to "penalize" the system every time a new unit is employed by adding the capital cost of the extra unit. This ensures that there is as little underutilization of units as possible. The drawback of using a mixed integer LP model is that shadow values are no longer valid and the sensitivity of the objective value to the constraints cannot be identified.

There are four main inputs considered in this MILP model. Firstly, the total volume that requires treatment is specified. Secondly, the capital and operations costs of each water management option are specified based on the calculations in Section 6.2. Lastly the total capacity available and unit capacity for every unit of each water management methods is considered.

The following water management options are being analyzed in the model:
1) Option 1, i=1 – Wastewater injection in disposal wells
2) Option 2, i=2 – Centralized Wastewater Treatment (CWT) for surface discharge
3) Option 3, i=3 – Onsite secondary treatment, blending and reuse

There are signification uncertainties involved in the cost, availability and capacity limits of the above water management options. Furthermore, the volume of water requiring treatment in the future is also uncertain as shown in Chapter 3. Realizing these limitations, the objective of this simplified model is not to present an optimum solution for the technology options used in the water management system. The objective is to analyze how events like future regulatory changes can affect current decisions with regards to the water management system.

6.4.1. Mixed Integer Linear Programming Formulation

This section presents the problem formulation for the mixed integer linear programming (MILP) model. The problem solved with this formulation is effectively a scheduling solution used to deploy water management units over multiple time periods in order to meet the water treatment need while minimizing costs. The objective function is to minimize costs, while accounting for penalty costs and discounting.

Objective function

$$\min TC = \sum_t \sum_i \left(\left(VC_{i,t} x_{i,t} + FC_{i,t} n\_new_{i,t} \right) \frac{1}{(1+dr)^t} \right) + g \left(\sum_t \left(\left(V_t - \sum_i x_{i,t} \right) \frac{1}{(1+dr)^t} \right) \right)$$

Constraints

$\sum_i x_{i,t} \leq V_t$	All treated water is less than or equal to the wastewater volume
$x_{i,t} \leq C_{i,t}$	All treated water is less than or equal to the available technology capacity
$n\_new_{i,t} c_{i,t} \geq x_{i,t} - x_{i,t-1}$	Relationship between number of new units and amount of water being treated
n_new	Number of units must be an integer
$x, n\_new \geq 0$	Physical values greater than zero

Variables – MODEL INPUTS:

V_t = flow rate of water to be treated [bbl/day]
$C_{i,t}$ = total capacity for each technology [bbl/day]
c_i = unit capacity for each technology [bbl/day]
FC_i = fixed cost for each technology [$]
VC_i = variable cost for each technology [$/bbl]
g = penalty cost for untreated water [$/bbl]
t = time [year]
i = technology options (1, 2, 3 …) [-]
dr = discount rate [-]

Variables - OUTPUT:
$x_{i,t}$ = water treated by each technology, i, at time t [bbl/day]
$n\_new_{i,t}$ = number of NEW units for each technology, i, at each time t [-]
TC[30] = total costs [$/day]

The model was developed using the GAMS software package. GAMS (General Algebraic Modeling System) is a high level modeling system for mathematical programming and optimization (GAMS, 2012). See Appendix I for the MILP formulation (GAMS code).

6.4.2. Model evaluation and Uncertainty limitations

The above model allows us to investigate the selection of different water management options over time based on a set of parameters such as cost, unit capacity, total capacity, volume of water requiring treatment. Furthermore it allows us to see how regulatory or technological changes over time can affect current water management decisions.

A limitation to the above approach is that the model does not account for the uncertainty in variables such as cost and volume of water requiring treatment. The approach is deterministic and optimizes the system based on the scalar inputs provided. For that reason, this simplified model is used to provide trends of how future technological and regulatory changes can affect current decisions, rather than provide a solution on what the optimum water management system could look like.

6.4.3. Model Inputs

The volume of water that needs to be managed is shown in Table 33:

	Volume of flowback and produced water (M bbl)[31]	**Bbl per day equivalent**
t=1 (2010)	8.7	23,797
t=2 (2011)	24.1	66,063

Table 33 – Volume of water requiring treatment

The remaining inputs into the model are shown in Table 34. Capital costs for each water management option had to be included as input assumptions. The expected cost of a new

[30] Total cost is an output of the model, however for the purposes of this study we are only interested in the technology portfolio and how it is affected by the input parameters.
[31] Based on PA DEP volumes (PA DEP, 2011a)

injection well is approximately $2,000,000 (Gaudlip et al., 2008). This includes drilling, monitoring and permitting costs. The capital cost for a 260,000 gallons per day CWT plant is estimated to be about $15,000,000 while the cost for small onsite treatment units performing secondary treatment is expected to be less than one million dollars. The capital cost for a 4000 gallons per day onsite treatment unit is estimated to be $750,000.

	Option 1 – Disposal well	**Option 2 – CWT**	**Option 3 – Onsite secondary treatment and blending**
Cost[32] [$/bbl]	6.7	7.7	6.2
Adjusted variable cost[33] [$/bbl]	6.4	7.4	4.4
Unit capacity [bbl/d]	1000[34]	6190[35]	100[36]
Number of units	200[37]	15[37]	100[38]
Discount rate	10%		
Penalty	Infinite		

Table 34 – Model inputs for MILP optimization

[32] Average values including trucking costs and water sourcing costs based on calculations in Ch. 6
[33] Costs from Chapter 6 excluding the capital cost assumptions made for the purpose of this model
[34] Gaudlip et al., 2008; PA DEP, 2011a
[35] 260,000 gallons/day (Veil & Puder, 2006) for 15 treatment plants (PA DEP, 2011a)
[36] 4000 gallons/day for 100 mobile treatment facilities – estimate calculated by PA DEP (2011a) data. The unit capacity for onsite treatment and blending facilities varies widely.
[37] Section 3.5.1. Currently out of the 200 disposal wells available in Ohio only about 25% of them are being used by Marcellus producers (PA DEP, 2011a)

6.4.4. Two-period model: Results and Analysis

The input parameters shown in Section 6.4.3 were used over two time periods. The results are shown in Table 35:

		Option 1 – Disposal well	Option 2 – CWT	Option 3 – Onsite secondary treatment and blending
Volume of water [bbl/day]	t=1	23,797	0	0
	t=2	66,063	0	0
Number of new units	t=1	24	0	0
	t=2	43	0	0

Table 35 – Model results based on input parameters shown in Section 6.4.3

Given the input parameters, the injection disposal method is the cheapest available technology and has sufficient capacity to treat all the wastewater. This indicates that at the given levels of capacity and costs, technology 2 and 3 are not cost competitive.

New onsite treatment and blending technologies can develop over time that achieve better unit capacities. Using the two-period model, the unit capacity of the onsite treatment unit was increased until it was economically favorable for it to be utilized. At 380 bbl/day Option 3 becomes economical. The results are shown in Table 36:

		Option 1 – Disposal well	Option 2 – CWT	Option 3 – Onsite secondary treatment and blending
Volume of water [bbl/day]	t=1	0	0	23,797
	t=2	18,063	0	38,000[38]
Number of new units	t=1	0	0	63
	t=2	29	0	38

Table 36 – Model results when onsite treatment is economically viable

The same analysis was repeated to derive what the required capital cost should be for a CWT facility to be competitive. At a capital cost of $12M a 260,000 gallons per day plant becomes economical (20% reduction in capital costs).

[38] Maximum capacity reached for Option 3

		Option 1 – Disposal well	Option 2 – CWT	Option 3 – Onsite secondary treatment and blending
Volume of water [bbl/day]	t=1	0	23,797	0
	t=2	0	66,063	0
Number of new units	t=1	0	4	0
	t=2	0	7	0

Table 37 – Model results when CWT facility treatment is economically viable

For a two-period model, the capital costs dominate the cost optimization decisions. In order to investigate the effects of variable costs and how future regulatory changes affect current decisions, we expand the model to operate over a longer time period.

6.4.5. Five-period model: Results and Analysis

The following model will cover five time periods and investigate how changes in regulation affect water management decisions. See Appendix I for MILP formulation.

Water treatment requirements need to be projected for five time periods. Drilling patterns determine the volume of flowback and produced water per year. Increasing drilling rates will increase the water volumes every year. Decreasing drilling rates will cause the water flow to increase at a decreasing rate and possibly converge to a steady volume[39].

In Section 2.3.1 the hypothetical maximum number of wells in the Marcellus was calculated to likely not be more than 3,000 wells per year. This value was used as the estimated number of wells in t=5. The number of wells (linearly extrapolated between time period 2 to 5) along with the flowback and produced water volumes for 2011 shown in Table 7 were used to project the water treatment need for 5 time periods. The results are shown in Table 38 and indicate the projected water treatment volumes based on the scenarios of increasing and decreasing drilling rates.

[39] Produced water continues to increase in volume

Increasing drilling rates		
	Number of 1st production wells	Flowback and produced water [bbl/day]
t=1 (2010)	1,486	23,797
t=2 (2011)	1,937	66,063
t=3	2,300	89,000
t=4	2,650	115,000
t=5	3,000	142,500

Decreasing drilling rates		
	Number of 1st production wells	Flowback and produced water [bbl/day]
t=1 (2010)	1,486	23,797
t=2 (2011)	1,937	66,063
t=3	2,300	89,000
t=4	1,800	89,000
t=5	1,650	89,000

Table 38 – Projected water treatment need based on increasing or decreasing natural gas drilling rates[40].

Regulatory Changes

As was discussed in Section 6.3.4, it is possible that availability of injection capacity for Pennsylvania operators might be reduced. Therefore instead of the 200 injection wells available, that number might be reduced to very few available wells. As an indicative reduction the available number of disposal wells for t=4 and t=5 is set to 50.

Designing the wastewater treatment system with this regulatory effect in mind can help save significant costs. Limiting the exposure of the system to this change in regulation results in the water management selection shown in Table 39.

[40] Values for 2010 and 2011 are data collected from PA DEP (2011a). Values for 2012 – 2014 are approximate rounded figures. These values are not based on a rigorous projection analysis. They are estimated for the purpose of using them in the 5-period MILP model in order to investigate how regulatory changes can affect the choice of water management options.

		Option 1 – Disposal well	Option 2 – CWT	Option 3 – Onsite secondary treatment and blending
Volume of water [bbl/day]	t=1	23,797	0	0
	t=2	50,797	15,266	0
	t=3	50,797	38,203	0
	t=4	50,000	65,000	0
	t=5	50,000	92,500	0
Number of new units	t=1	24	0	0
	t=2	27	3	0
	t=3	0	4	0
	t=4	0	4	0
	t=5	0	4	0

Table 39 – Model results with foresight about future changes in regulation

If there is no consideration for the fact that regulation might change, there will be overinvestment in the cheaper technology (disposal wells) as shown in Table 40. Regulation will later prohibit the use of the already developed capacity, therefore the capital cost for that development would be lost.

		Option 1 – Disposal well	Option 2 – CWT	Option 3 – Onsite secondary treatment and blending
Volume of water [bbl/day]	t=1	23,797	0	0
	t=2	66,063	0	0
	t=3	89,228	0	0
	t=4	50,000	65,000	0
	t=5	50,000	92,500	0
Number of new units	t=1	24	0	0
	t=2	43	0	0
	t=3	23	0	0
	t=4	0	11	0
	t=5	0	4	0

Table 40 – Model results without foresight about future changes in regulation

Taking into account future possible changes in regulation lead to an investment in 51 disposal wells and 15 CWT facilities. Not accounting for changes in regulation lead to an investment in 90 disposal wells during the first three time periods. After time period 4, only 50 disposal wells could be used therefore a subsequent investment in 15 CWT facilities was necessary.

The cost is approximately 5% higher for the scenario where regulation change is not considered (this accounts for discounting capital investment costs over time). Foresight can help optimize the wastewater treatment technology portfolio and decrease overall costs.

7. Chapter 7 – Synthesis and Conclusions

7.1. Re-statement of the Thesis Question

The emergence of large-scale hydrocarbon production from shale rock resources has revolutionized the oil and gas sector, and hydraulic fracturing has been the key enabler of this advancement. As a result, the need for water treatment has increased significantly and became a major cost for producers. What to do with the flowback water in light of scarce disposal facilities and substantial handling costs is a major impediment to the development of the natural gas resource, particularly in the Marcellus shale.

This thesis provides a framework on how to evaluate water management options for hydraulic fracturing wastewater and is using the Marcellus shale as a case study. Using this framework we provide guidelines for assessing water management options under large uncertainties about water treatment needs, technology cost and availability and regulatory changes. The cost of water treatment technologies applicable to the Marcellus region is estimated based on industry data and the technical limitations of these technologies are evaluated. A techno-economic study is performed on the various water management options available ranging from simple injection disposal to advanced centralized and on-site treatment and reuse options.

The main objective of the thesis is to identify the key factors that affect the choice of water management options in the Marcellus region. Furthermore, the work investigates how technological, industrial and regulatory changes can affect water treatment technology options and infrastructure investments.

7.2. Conclusions and Key findings

This work provides insights on flowback and produced water management in Pennsylvania (Marcellus shale). Particular emphasis was given to the composition of wastewater, the regulations that govern wastewater handling and the economic viability of water management options.

The three main wastewater management options available to the oil and gas producers are (a) water injection in disposal wells, (b) water reuse in hydraulic fracturing operations and (c) high level treatment (desalination) for surface discharge or beneficial use. In Pennsylvania, flowback water is not sent to disposal wells but rather is being reused or sent to Centralized Wastewater Treatment (CWT) facilities. In 2011, for the total volume of both produced and flowback water in Pennsylvania 61% is sent to CWT facilities, 31% is reused and 8% is sent to disposal wells. The fact that injection is not available locally in Pennsylvania results in high transportation costs if operators chose to send water to out of state disposal wells. The distance between a well site and the disposal well plays a decisive factor in determining the viability of this water management method. Reuse of water is gaining popularity with some large operators like Cabot Oil & Gas Corp reusing 100% of their flowback water. It is possible that large operators are able to reuse all the water for subsequent fracturing jobs because they have extensive drilling activities in the Marcellus. Water blending and reuse has been shown to be a very cost effective water management method assuming that the composition of the flowback is such that it can be reduced to the required levels for re-fracturing after blending.

Water Geochemistry

Composition of flowback and produced water (TDS, chlorides, hardness concentration) varies widely within Marcellus shale. The water management solutions adopted within the Marcellus shale depend on the specific composition of flowback from each independent region. It is unlikely that one type of management method will be appropriate across the Marcellus shale. Depending on the composition of the flowback, varying levels of treatment, or even blending without treatment, can be sufficient to produce a viable quality water for reuse in subsequent hydraulic fracturing. Furthermore, flowback and produced water should be treated differently. The differences in flow rates, and more importantly the differences in compositions make some management options more attractive than others. Since the concentration of contaminants (TDS, hardness, etc.) in wastewater increases over time, produced water is more saline than flowback water. Treatment options are expected to be used to treat less saline flowback water while disposal options like injection wells are expected to be used to manage more contaminated flows that would require higher operational costs in order to desalinate. As discussed through this study, the main issue with hydraulic fracturing wastewater is not the high TDS concentrations but the hardness ions concentrations, which can cause significant scaling. Barium and strontium concentrations present the higher risk with regards to precipitating in sulfate salts. Minimizing these ions to a concentration of less than 25ppm in the re-fracturing fluid should be a high priority with regards to water treatment.

Water Management Pathways

There were six water management pathways analyzed in detail in this study. The first pathway involves the injection of untreated flowback water to disposal wells. There is no treatment involved in that pathway. The second pathway identified is blending of untreated flowback and direct reuse of the resulting fluid in subsequent hydraulic fracturing. This approach is possible if the composition of flowback is such that direct blending and dilution can reduce the composition of the resulting fluid to levels acceptable for reuse. However, the approach has the risk of affecting fluid stability, due to the TDS concentration, presence of hardness ions and FOG, and can cause blockages in the well due to scaling and increased concentration of TSS. The next two water management pathways identified involve onsite (a) primary and (b) primary and secondary treatment before blending and reuse. Approach (a) removes solids and FOG before reuse while approach (b) also reduces the hardness concentration. This can eliminate some of the problems mentioned above for the pathway using no treatment. The last two water management pathways involve desalination techniques, which means they treat the water by removing most of the salts (TDS, hardness ions, Iron and Manganese etc.). One of the desalination pathways is for water treatment performed onsite with the objective of reusing the treated water for hydraulic fracturing. In areas with lack of fresh water it is possible that treatment is performed at a CWT facility and water is then returned to the site for reuse. Since water availability in the Marcellus shale region is not an issue this is unlikely. The last desalination pathway is for desalination treatment performed at a CWT facility with the objective to discharge the treated water to surface waters and possibly use the concentrated brine product for beneficial use, such as road salt.

Evaluating Water Management Costs

When evaluating water management options one needs to consider the full cost (including treatment cost, transportation cost for wastewater, sourcing cost for make-up water and transportation of make-up water) of treatment. Not considering the cost of water required for subsequent fracturing operations can lead to misleading results and misrepresent the competitive advantage of technologies that have the ability to reuse flowback water. Including the sourcing and transportation costs of make-up water in the calculation reduces the cost competitiveness of injection in disposal wells and treatment at CWTs, since those two options require the sourcing of 100% make-up water for the next fracturing job. Make-up water needs are determined by the technology recovery factors and by blending requirements, which largely depend on the composition of the flowback. The above factors play a key role in the economic viability of all the reuse options since the cost savings of having to source less make-up water are significant.

The blending and reuse of untreated flowback water is the most economical water management option; however, it might be prohibited due to the flowback composition.

The following two water management options, (1) Primary treatment, blending and reuse and (2) Secondary treatment, blending and reuse; could be cost competitive against the option of injecting wastewater in disposal wells. Selection between those three options depends on the flowback composition and proximity to the disposal well. Based on our current assumptions, onsite tertiary treatment (desalination) technologies seem to not be economically viable. However, some operators might adopt them due to public relation reasons rather than financial reasons.

Distance between the well site and the disposal well is one of the most important factors in deciding among water management options. Based on the assumptions in this thesis, if the disposal well is more than 100 miles away from the well site, treatment, blending and reuse options become economically competitive. This assumes that the flowback composition can be reduced to acceptable levels for reuse. Furthermore, if the disposal well is even further away (approximately 200 miles) then CWT facilities can become a more cost effective option than disposal wells. A location analysis indicated that well sites located in northeast Pennsylvania are unlikely to find injection in disposal wells a cost effective water management option. This is also supported by the PA DEP data that indicates that only 8% of Marcellus wastewater in 2011 was injected in disposal wells.

Trucking costs have the potential to significantly affect the choice of water management method used. At the current assumed range of operational trucking cost ($0.02 - $0.03 per bbl per mile) trucking does not affect the choice of water management system. However, any subsequent increase on the order of more than 30% in the operational cost of trucking could potentially result in onsite treatment services being preferred over disposal wells or CWT. Increases in trucking costs are likely to occur due to the increased demand for water hauling services in the Marcellus shale.

Onsite treatment options will only be used if there is potential for wastewater reuse. If there is no potential for wastewater reuse it is cost effective to send the wastewater to a disposal well or a CWT facility. At current cost assumptions, if drilling rates for new wells in Marcellus shale decreases, which is likely given the current gas prices, there will probably be low demand for water reuse and thus low demand for onsite treatment. Currently, onsite tertiary treatment facilities are only viable if they perform at least partial reuse of wastewater. Significant innovation and cost reduction in tertiary onsite treatment is necessary if they will be used without performing significant water reuse. There is currently significant investment and development in onsite treatment technologies. If there is a reduction in wastewater reuse potential, the long-term viability of onsite treatment technologies could be in jeopardy and investments in this management method might not be utilized for the duration of the technology's lifetime.

Availability of disposal wells could possibly be restricted due to increased activity in Ohio oil-rich shale exploration. Restriction in disposal capacity coupled with decreased shale gas drilling rates in the Marcellus shale, will probably result in CWT facilities being the most cost efficient water management method. Given the new discharge regulations by PA DEP there is very little availability of new capacity for wastewater treatment at CWTs. This can potentially create a problem and force producers to adopt very expensive water management treatment options. Having this foresight and investing in more CWT capacity could help mitigate some of the economic and operational risks involved in this scenario.

Factors affecting water management options

To summarize, the main factors that can affect the selection of water management options and were analyzed in this thesis are the following:

- Make-up water requirements which depend on the flowback composition and the technology recovery factors
- Proximity of gas well site to disposal well facilities
- Operational trucking costs
- Natural gas drilling patterns and potential for wastewater reuse
- Regulatory constraints for disposal well availability

7.3. Policy Conclusions and Recommendations

This work yields important insights that help inform the policy debate on how best to address both the environmental and operational water issues associated with hydraulic fracturing in the Marcellus region.

The policy recommendations listed below are aimed to start the discussion around this topic and use information that was discussed in this thesis to address some of the rising environmental and operational issues.

Recommendations

Wastewater management for hydraulic fracturing operations is very location specific and depends on the geological characteristics of each location. The current approach where bespoke state regulations are used to regulate water treatment and disposal options is perceived to be the right approach since you cannot have a national water management system that fits the needs of all the geographic areas. Nevertheless, the system could benefit from a widely accepted national agency that could provide support and promote new, innovative water treatment technologies. Based on the findings of this study all desalination technologies that can effectively minimize TDS and hardness concentrations are prohibitively expensive when used onsite. The industry is lacking a cost effective technology that could address these main contaminant issues. Private companies, universities and governmental agencies are currently carrying out research in water treatment technology innovation. Combining some of these resources or creating a forum to share information would help promote the development of a sustainable water management solution for the shale gas industry. A recommendation is to establish an independent governmental group or institution that attempts to identify and promote technologies that fit the economic and technological criteria mentioned above. This endeavor could be beneficial for all stakeholders involved and could promote industry wide collaboration.

Federal regulations currently prohibit the disposal of wastewater from onshore oil and gas wells to surface waters even if that water is treated to the required clean water limits. As discussed in this thesis, allowing localized discharge from onshore oil and gas wells, which would minimize trucking costs, will probably not result in a significant economic benefit for onsite treatment technologies. Onsite treatment and discharging facilities will only be economically sustainable at current costs when combined with partial water reuse. Furthermore, water discharge from onsite facilities will be hard to regulate and monitor resulting to increased risk for disposal of flowback to surface water that can lead to contamination. Therefore, it is recommended to continue with current status quo and not consider allowing surface water discharge from onsite facilities.

Lastly, there should be better reporting and documentation of wastewater volumes (both flowback and produced water) as well as a documentation of how that water is currently managed. The PA DEP began collecting this data specifically for the Marcellus shale in 2010, however as was discussed in this thesis, data is not yet consistent and there are indications that the reported volumes are not representative of the whole region. Accurate and timely reporting would provide insight into the current state of the industry and facilitate future decisions. Make-up water for subsequent fracturing jobs is a significant portion of the cost for water management, therefore a reporting tool to help make efficient use of the wastewater produced and determine reuse opportunities could be beneficial. Two of the limiting factors for water reuse is that (a) the timing for subsequent fracturing jobs is not in line with the flowback being produced from the well and (b) the operator might not have enough drilling activity in the Marcellus shale and therefore does not need to reuse the water for new hydraulic fracturing jobs. More integration and water reuse between producers could help optimize the use of water in oil and gas operations. However, this suggestion might be faced with skepticism and concern from oil and gas operators. Fracturing fluid composition is considered key to successful fracturing jobs and operators would probably be unwilling to share any information or wastewater that might allow other operators to understand more about their operations. Nevertheless, a wastewater management and reporting system that focuses on the optimization of water reuse could offer significant efficiencies in terms of reducing costs and minimizing negative environmental impacts. Such a program can gain support from the local community and be reinforced through state government.

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APPENDICES

Appendix A – Type Curve Characteristics for all Plays

Estimation of production rate as a function of time is of great importance and well characterized from several authors in the broad literature (Arps, 1945; Chen, 2003). Under natural well depletion, the rate of production normally declines with recovery. The majority of oil and gas reservoirs show natural production rate decline according the standard trends. This natural decline trend is expected to continue until abandonment unless the natural trend is interrupted by events like water injection or well shut down. The Type Curve (TC) displays the production rate for an average well in a particular play with a given start production date. The TC can be extrapolated to project the production rate of the well over its production lifetime.

Decline curve analysis (DCA) is one of the most widely used techniques for estimated ultimate recovery (EUR) calculation and will be employed in this study. The natural decline trend is dictated by natural drive, rock and fluid properties, well completion methods and other factors. Thus, an advantage of decline trend analysis is implicit inclusion of all production and operating conditions that would influence the performance.

The three standard production decline models are defined as follows:

- Exponential rate decline: $$q(t) = q_i \exp(\ D_o t) \qquad \text{(A.1)}$$
- Harmonic rate decline: $$q(t) = \frac{q_o}{(1 + D_o t)} \qquad \text{(A.2)}$$
- Hyperbolic rate decline: $$q(t) = \frac{q_o}{(1 + nD_o t)^{1/n}} \qquad \text{(A.3)}$$

where q: production rate [mcfd]; q_o: initial production rate [mcfd]; D_o: initial decline rate at time zero [mcfd]; t: time; n: hyperbolic exponent [constant]

The hyperbolic rate decline shown above is the empirical Arps equation (Arps, 1945) that will be used in this analysis.

Limitations in Decline Curve Analysis

<u>Arps equation</u>

The Arps equation was designed for conventional reservoirs and assumes constant permeability and constant skin factor for the well being analyzed. If permeability decreases as pore pressure decreases or if skin factor changes because of changing damage or deliberate stimulation the character of the well's decline changes. Shale gas reservoirs are characterized by transient production behavior and in general boundary-dominated flow is rarely observed in the data (Anderson et al., 2010). Shale gas production rates exhibit steep initial decline trends as production is dominated by flow from hydraulic fractures to the wellbore. As time progress the production rate decline becomes small with a long tail. This low production rate is dominated by transient flow, which is a reflection of low permeability. This results in a DCA that often yields unconventional hyperbolic exponent values, n, which are greater than 1.0.

Production variations over time

Production profiles and decline curves tend to vary over time thus groups of wells are separated based on their date of first production (DOFP). Some of the reasons why this can occur are the following:

- Production improvement due to technological advancements may improve the initial production (IP) rates and/or increase the horizontal length.
- Interference between new and older wells. In a few cases newer hydraulic fracture operations can penetrate older fractures and offset the production profile of older wells
- Completion and stimulation practices, such as the volume of fluid and proppants, may change over time. As a note, it is not clear that these processes are also optimized over time so even though there are changes in operational process they might not lead to obvious gains in production.
- New wells may be drilled in areas within the same play where rock properties vary considerably.
- High reservoir pressures may force operators to control drawdown to avoid any unnecessary damage in the well and the reservoir.

Correction adjustments

To deal with the above limitations of the Arps (1945) equation, in this study, we used 'auto-decline' functionality on the data during analysis and careful consideration was taken on whether or not to include outlying data points. This helped achieve consistency across our results and other decline curves in the literature.

Data Analysis

Data was collected for all horizontal wells beginning production on June 1st of every year from 2005 to 2010. Type curve data is the average production from all the wells starting production on the same date. Equation (A.3) was fitted as described above to type curves from all the basins to determine the type curve parameters, n and D_o. Only type curves with more than one and a half years of production data were used. Where reliable data was not available, type curve parameters from the MIT Future of Natural Gas Study (MITEI, 2011) were used. The type curve data was collected from the production database of HPDI, LLC (HPDI, 2011).

Figure A.1 illustrates the 2005-2010 type curves collected for one of the shale plays, Barnett.

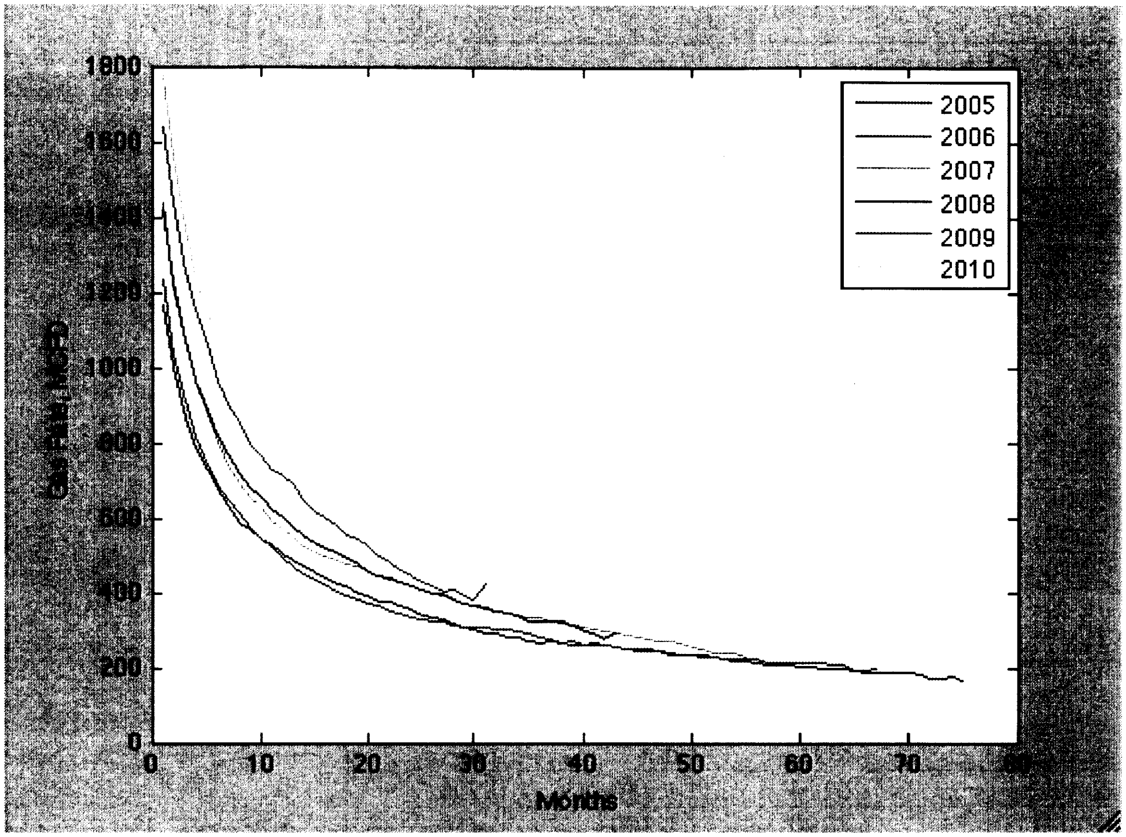

Figure A.1 – Barnett Shale Type Curves for 2005-2010 (HPDI, 2011)

The type curve parameters, as shown in Equation (A.3), that are derived from the curve fitting analysis are shown in Table 1. These were used to project natural gas production from these basins for the next 30 years.

BARNETT			
Year	q_o	n	D_o
2006	1433	1.755	0.213
2007	1443	1.706	0.199
2008	1418	1.635	0.173
2009	1633	1.342	0.146
2010	1773	1.464	0.150
FAYETTEVILLE			
Year	q_o	n	D_o
2006	1149	1.456	0.153
2007	1305	1.300	0.138
2008	1848	1.220	0.136
2009	2028	1.332	0.132
2010	2234	1.476	0.122
HAYNESVILLE			
Year	q_o	n	D_o
2006	n/a	n/a	n/a
2007	n/a	n/a	n/a
2008	6114	1.786	0.400
2009*	8290	1.300	0.450
2010*	8451	1.300	0.4500
MARCELLUS			
2006	n/a	n/a	n/a
2007	n/a	n/a	n/a
2008*	535	1.500	0.400
2009*	1770	1.500	0.400
2010*	2826	1.500	0.400
WOODFORD			
2006*	1331	1.229	0.1217
2007*	1265	1	0.15
2008	2291	1.25	0.13
2009	2717	0.9818	0.1032
2010	3469	1.24	0.1596

Table A.1 – Type curve parameters for all shale plays
*Inconsistent decline rates - data taken from MIT Future of Natural Gas Study (MITEI, 2011)

Shale gas plays are described by steep decline rates within the first year and slower steady production in subsequent years until depletion. Each play is distinctively different and may vary with regards to the initial decline rates and annual production rates. This depends on a variety of factors which include, among others, differences in the rock formation, well completion processes and hydraulic fracturing additives. Figure A.2 illustrates the 2010 type curves for the four main shale regions (Woodford had insufficient data for 2010 production wells). The decline rates of all the basins as characterized by the above 2010 type curves are shown in Table A.2. It is clear that Haynesville shale has by far the steepest decline in terms of production rates. As we will investigate in Section 3.3, production rates are closely linked to produced water quantities and can have a large effect on the water management options.

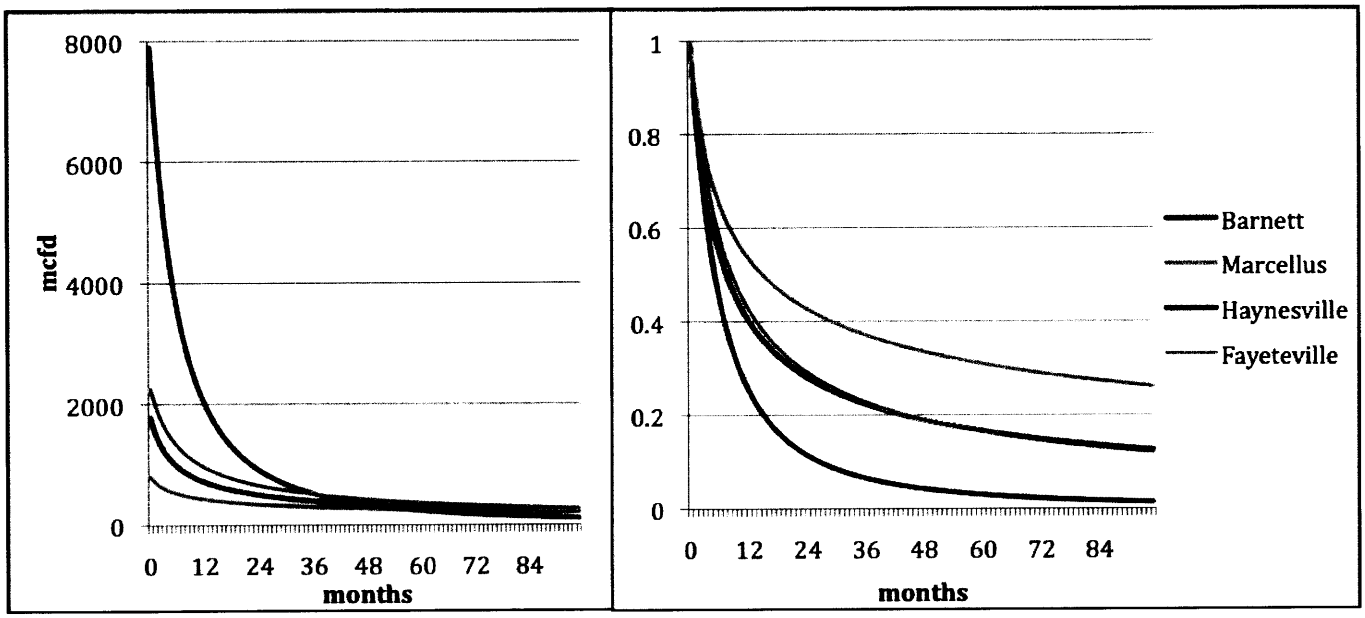

Figure A.2 – Type Curves for 2010 production wells. Left: Conventional type curves demonstrating differences in production levels and production rates for four major shale plays. Right: Normalized type curves illustrating differences in decline rates.

	Barnett	Fayetteville	Haynesville	Marcellus
1st year	59%	58%	75%	47%
2nd year	33%	32%	55%	20%
3rd year	20%	22%	43%	13%
4th year	15%	17%	35%	10%

Table A.2 – Production decline rates for 2010 type curves (starting date June 1st, 2010)

Appendix B – Types of Injection Wells

(EPA, 2011c)

Class II wells inject fluids associated with oil and natural gas production. Most of the injected fluid is salt water (brine), which is brought to the surface in the process of producing (extracting) oil and gas. In addition, brine and other fluids are injected to enhance (improve) oil and gas production.

- Approximately 144,000 Class II wells in operation in the United States
- Inject over 2 billion gallons of brine per day
- Most oil and gas injection wells are in Texas, California, Oklahoma, and Kansas

Class II-R = Enhanced Recovery Wells

Inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and—in some limited applications—natural gas. This is also known as secondary or tertiary recovery. The injected fluid thins (decreases the viscosity) or displaces small amounts of extractable oil and gas, which is then available for recovery. In a typical configuration, a single injection well is surrounded by multiple production wells. Production wells bring oil and gas to the surface; the UIC Program does not regulate production wells. Enhanced recovery wells are the most numerous type of Class II wells, representing as much as 80 percent of all Class II wells.

Class II-D = Disposal Wells

Inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. When oil and gas are produced, brine is also brought to the surface. The brine is segregated from the oil and is then injected into the same underground formation or a similar formation. Class II disposal wells can only be used to dispose of fluids associated with oil and gas production. Disposal wells represent about 20 percent of Class II wells.

Requirements for Class II wells

Section 1422 of the Safe Drinking Water Act requires states to meet EPA's minimum requirements for UIC programs and demonstrate that their existing standards are effective in preventing endangerment of USDWs. Programs authorized under section 1422 must include construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators.

Appendix C – Water usage per well to drill and fracture

Play	Water (M gal)	Drilling / Fracture Volumes or Both	Date	Source
Marcellus	2.7	Fracture	2010	SRBC, Susquehanna River Basin Commission
Marcellus	5.6	Both	2010	Chesapeake
Marcellus	3.9	Both	2008	ALL Consulting
Marcellus	3.8	Fracture	2008	EPA
Marcellus	3.9	Both	2007-08	Chesapeake
Marcellus	3.8	Fracture	2007-08	Chesapeake
Eagleford	6.1	Both	2010	Chesapeake
Barnett	3.8	Both	2010	Chesapeake
Barnett	2.7	Both	2008	ALL Consulting
Barnett	2.3	Fracture	2008	EPA
Barnett	3.2	Both	2008	Chesapeake
Barnett	3.4	Both	2007-08	Chesapeake
Barnett	2.9	Fracture	2007-08	Chesapeake
Haynesville	5.6	Both	2010	Chesapeake
Haynesville	3.7	Both	2008	ALL Consulting
Haynesville	2.7	Fracture	2008	EPA
Haynesville	3.8	Both	2007-08	Chesapeake
Haynesville	2.7	Fracture	2007-08	Chesapeake
Fayetteville	3.1	Both	2008	ALL Consulting
Fayetteville	2.9	Fracture	2008	EPA
Fayetteville	3.0	Both	2007-08	Chesapeake
Fayetteville	2.9	Fracture	2007-08	Chesapeake

Table C.1 – Water Usage for Hydraulic Fracturing and Drilling in five Shale plays (SRBC, 2010; DOE & ALL Consulting, 2009; Chesapeake, 2008; EPA, 2011b; Chesapeake, 2010)

Appendix D – PA DEP Code Chapter § 95.10. Treatment requirements for new and expanding mass loadings of Total Dissolved Solids (TDS)

(PA DEP, 2012)

(a) The following are not considered new and expanding mass loadings of TDS and are exempt from the treatment requirements in this section:

(1) Maximum daily discharge loads of TDS or specific conductivity levels that were authorized by the Department prior to August 21, 2010. These discharge loads will be considered existing mass loadings by the Department.

(i) Relocation or combination of existing discharge points of existing mass loadings of TDS do not constitute a new or expanding mass loading unless total mass loadings are increased.

(ii) Existing publicly owned treatment works (POTW) as defined in § 92.1 (relating to definitions) and industrial waste treatment facilities authorized prior to August 21, 2010, under permits authorizing the acceptance, treatment and discharge of TDS do not constitute a new or expanding mass loading unless total mass loadings accepted, treated and discharged are to be increased. Only the net increase in TDS mass loadings from these facilities will be considered a new and expanding mass loading of TDS.

(2) Facilities treating postmining pollutional discharges from abandoned mine sites. For purposes of this section, abandoned mine sites include all lands and water eligible for reclamation or drainage abatement or treatment expenditures under section 402(g)(4) or section 404 of the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C.A. § § 1232(g)(4) and 1234).

(3) Surface mining activities with preexisting discharges subject to Chapter 87, Subchapter F or Chapter 88, Subchapter G (relating to surface coal mines: minimum requirements for remining areas with pollutional discharges; and anthracite surface mining activities and anthracite bank removal and reclamation activities: minimum requirements for remining areas with pollutional discharges) and preexisting discharges subject to Chapter 90, Subchapter F (relating to coal refuse disposal activities on areas with preexisting pollutional discharges).

(4) Discharges from active surface coal mining operations with an open pit dimension of less than 450,000 square feet exposed at any time.

(5) Discharges from erosion and sediment control facilities used at surface mining activities as defined in § 86.1 (relating to definitions).

(6) Existing mine drainage directed to a mine pool where the mine pool is being treated in accordance with applicable requirements in Chapters 91—96.

(7) New and expanding discharge loadings of TDS equal to or less than 5,000 pounds per day, measured as an average daily discharge over the course of a calendar year, otherwise known as the annual average daily load.

(8) Discharges of wastewater produced from industrial subcategories with applicable effluent limit guidelines for TDS, chlorides or sulfates established as best available technology economically achievable (BAT), best conventional pollutant control technology (BCT) or new source standards of performance, by the administrator of the EPA under sections 303(b) and 306 of the Federal Act (33 U.S.C.A. § § 1314(b) and 1316).

(b) Operations with wastewater resulting from fracturing, production, field exploration, drilling or completion of natural gas wells shall comply with the following requirements:

(1) Except as provided in paragraph (3), there may be no discharge of wastewater into waters of this Commonwealth from any source associated with fracturing, production, field exploration, drilling or well completion of natural gas wells.

(2) A wastewater source reduction strategy shall be developed by the well operator by August 22, 2011, and submitted to the Department upon request. The source reduction strategy must identify the methods and procedures the operator shall use to maximize the recycling and reuse of flow back or production fluid either to fracture other natural gas wells, or for other beneficial uses approved under Chapter 287 (relating to residual waste management—general provisions). The strategy shall be updated annually and include, at a minimum, the following information:

(i) A complete characterization of the operator's wastewater stream including chemical analyses, TDS concentrations and monthly generation rate of flowback and production fluid at each natural gas well.

(ii) A description and evaluation of potential wastewater source reduction options through recycling, reuse or other beneficial uses.

(iii) The rationale for selecting the source reduction methods to be employed by the operator.

(iv) Quantification of the flowback and production fluid generated by each well which is recycled or reused either to fracture other natural gas wells or for other approved beneficial uses.

(3) New and expanding treated discharges of wastewater resulting from fracturing, production, field exploration, drilling or well completion of natural gas wells may be authorized by the Department under Chapter 92 (relating to National Pollutant Discharge Elimination System permitting, monitoring and compliance) provided that the following requirements are met:

(i) Discharges may be authorized only from centralized waste treatment facilities (CWT), as defined in 40 CFR 437.2(c) (relating to general definitions).

(ii) Discharges may not be authorized from a POTW, as defined in § 92.1, unless treatment at a CWT meeting all of the requirements of this chapter precedes treatment by the POTW.

(iii) The discharge may not contain more than 500 mg/L of TDS as a monthly average.

(iv) The discharge may not contain more than 250 mg/L of total chlorides as a monthly average.

(v) The discharge may not contain more than 10 mg/L of total barium as a monthly average.

(vi) The discharge may not contain more than 10 mg/L of total strontium as a monthly average.

(vii) The discharge complies with the performance standards in 40 CFR 437.45(b) (relating to new source performance standards (NSPS)).

(4) Deep well injection of wastewater resulting from fracturing, production, field exploration, drilling or well completion of natural gas wells shall comply with § 78.18 (relating to disposal and enhanced recovery well permits).

(c) New and expanding mass loadings of TDS not addressed in subsections (a) and (b) may not contain more than 2,000 mg/L of TDS as a monthly average, unless a variance is approved by the Department under this section. For purposes of this subsection, any net increase in existing TDS loadings authorized after August 21, 2010, will be considered a new and expanding mass loading of TDS.

(d) A request for a variance to subsection (c) shall be submitted to the Department and be accompanied by the following information:

(1) An analysis of the applicant's existing discharge loads of TDS, and the projected new discharge loads associated with the proposed new and expanding mass loadings of TDS.

(2) An analysis of the applicant's existing treatment facilities and the ability of those facilities to meet the requirement in subsection (c).

(3) An analysis of upgrades necessary to bring the applicant's existing facility into compliance with subsection (c) and the estimated costs associated with the upgrades.

(4) An analysis of the receiving stream's water quality for TDS at, or upstream from, the proposed point of discharge.

(e) A request for a variance to subsection (c) will be subject to the public notice requirements for permit applications in § 92.61 (relating to public notice of permit application and public hearing).

(f) A variance to subsection (c) may be approved by the Department only under the following conditions:

(1) A watershed analysis conducted by the Department determines that a variance will not result in a reduction of available assimilative capacity for TDS to less than 25% of the total available assimilative capacity at the next downstream point of water quality standards compliance. Available assimilative capacity will be calculated using design flow conditions under § 96.4(g) (relating to TMDLs and WQBELs).

(2) The resulting instream concentration of TDS at the point of discharge from the new or expanding loading will not violate water quality standards in Chapter 93 (relating to water quality standards).

(g) Coal-fired electric steam generating units subject to effluent limitations in 40 CFR Part 423 (relating to steam electric power generating point source category), including TDS effluent limitations created by the EPA rulemaking on effluent limitations scheduled for completion by March 2014 (Docket No. EPA-HQ-OW-2009-0819), must comply with subsection (c) by December 31, 2018, unless exempted by subsection (a).

Authority

The provisions of this § 95.10 issued under sections 5 and 402 of The Clean Streams Law (35 P. S. § § 691.5 and 691.402) and section 1920-A of The Administrative Code of 1929 (71 P. S. § 510-20), unless otherwise noted.

Source

The provisions of this § 95.10 adopted August 20, 2010, effective August 21, 2010, 40 Pa.B. 4835.

Appendix E – Time series flowback composition analysis by Blauch et al., 2009

The data in Appendix analysis presents a time series flowback analysis carried out by Blauch et al. (2009). The chemical composition of flowback water over time is analyzed to derive conclusions about the concentration variations of different constituents over time. The data presented is for a well in the Marcellus shale. Table E.1 presents the composition of flowback over time. The Appendix then shows a short analysis of the results.

Flowback (bbl):	12,000 bbl	13,000 bbl	14,000 bbl	15,000 bbl
Anions				
P Alkalinity (mg/L as $CaCO_3$)	0	0	0	0
M Alkalinity (mg/L as $CaCO_3$)	280	240	200	160
Chloride (mg/L as Cl^-)	54,000	59,000	62,900	67,800
Sulfate (mg/L as SO_4^{2-})	31	20	20	24
Cations				
Sodium (mg/L as Na^{1+})	26,220	28,630	31,810	35,350
Potassium (mg/L as K^{1+})	1,119	1,201	1,350	1,480
Calcium (mg/L as Ca^{2+})	7,160	7,680	8,880	9,720
Magnesium (mg/L as Mg^{2+})	341	463	488	805
Total Hardness (mg/L as $CaCO_3$)	19,300	21,100	24,200	27,600
Barium (mg/L as Ba^{2+})	28.9	43.3	99.6	175.7
Strontium(mg/L as Sr^{2+})	1,110	1,305	1,513	1,837
Iron, Ferrous (mg/L as Fe)	0.4	0.9	1.1	3.3
Iron, Total (mg/L as Fe)	63	66	72	78
Miscellaneous				
pH	6.22	6.08	5.98	5.88
Total Suspended Solids (mg/L)	144	175	498	502
Specific Gravity (g/ml)	1.065	1.068	1.077	1.087
Conductivity (micromhos)	133,100	141,500	157,600	173,200
Δ ATP (rlu) – Microbiological Content	1	3	1	1
Microbiological Content	low	low	low	low
Langelier Saturation Index (LSI)	1.02	0.84	0.72	0.55
Langelier Potential	Scaling	Mildly Scaling	Mildly Scaling	Mildly Scaling

Table E.1 – Marcellus shale well; Late stage flowback water chemical characterization data (Blauch et al., 2009)

Conclusions from flowback chemical analysis:

- The amount of dissolved constituents increased as flowback progressed (Figure E.1)
- Sodium and calcium are the most prevalent cations (Figure E.1)
- Alkalinity and pH dropped as flowback progressed, potentially explaining the rise of calcium levels. (Table E.1)
- Sulfate scaling is likely as calcium is rising while sulfate is dropping (Figure E.1 and E.2)
- The sharp rise in barium levels in the latter stages of flowback (at about 30% load recovery) suggest potential barium sulfate scale formation during the last portion of the flowback. The solubility of barium sulfate is very low and it can be a very aggressive scale. Since BaSO4 has very low solubility, when Ba2+ concentration is high, SO4—is low and vice versa. (Figure E.2 and E.4)
- Iron content in the flowback increased as flowback progressed (Table E.1)
- Chemical composition of these waters can be classified as highly saline (Figure E.2)
- With cations such as Mg, Sr and Ba, chemical signatures of the waters are consistent with an evaporite and carbonate rich source (Figure E.3 and E.4)

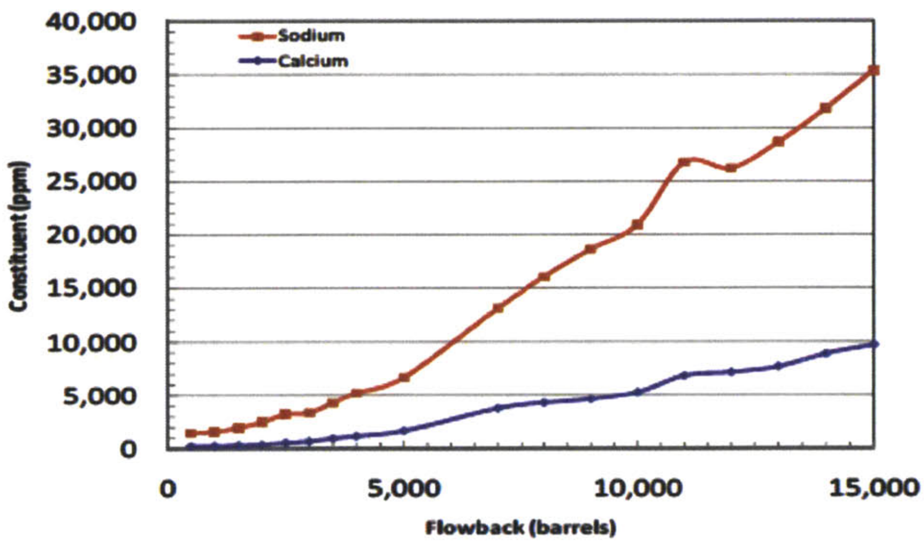

Figure E.1 – Marcellus shale well; A flowback analysis – major cation trend (Blauch et al., 2009)

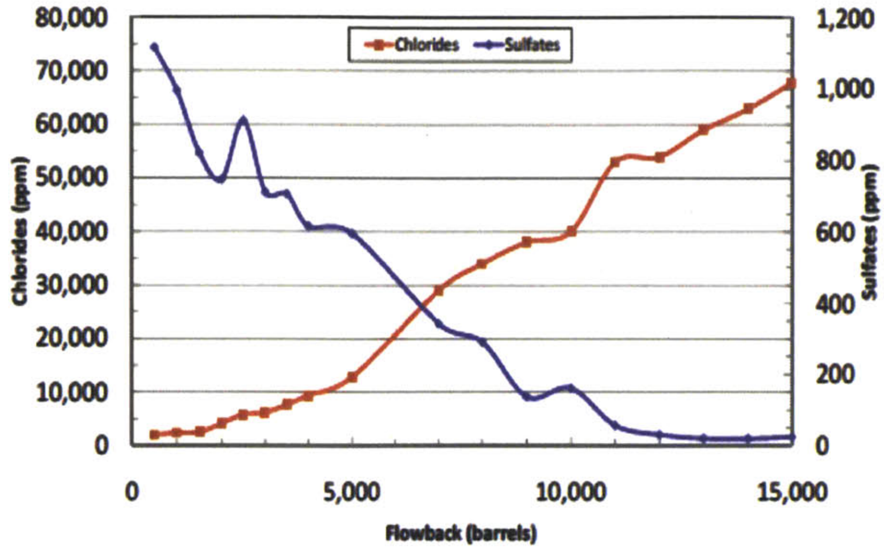

Figure E.2 – Marcellus shale well; A flowback analysis – anion trend (Blauch et al., 2009)

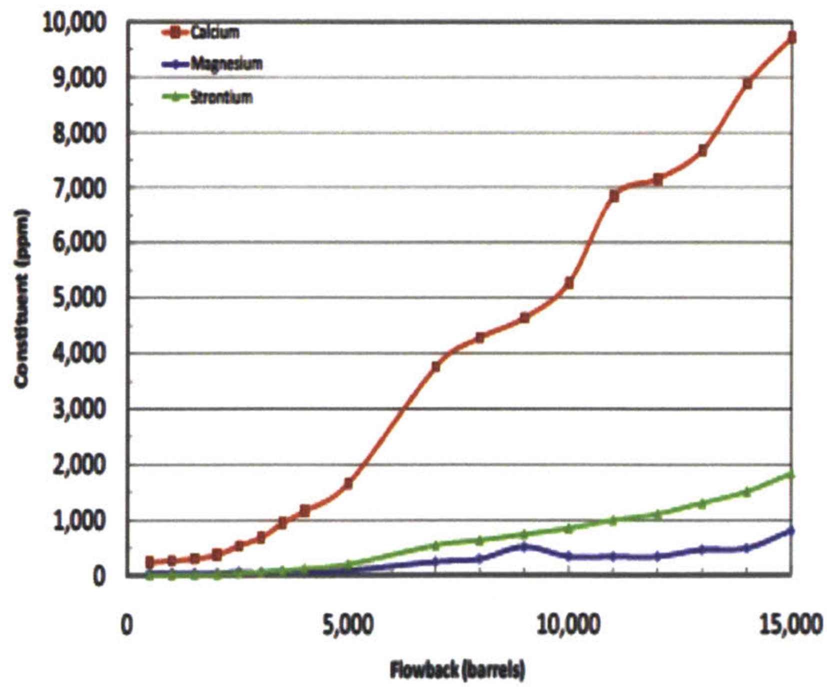

Figure E.3 – Marcellus shale well; A flowback analysis – divalent cation trend (Blauch et al., 2009)

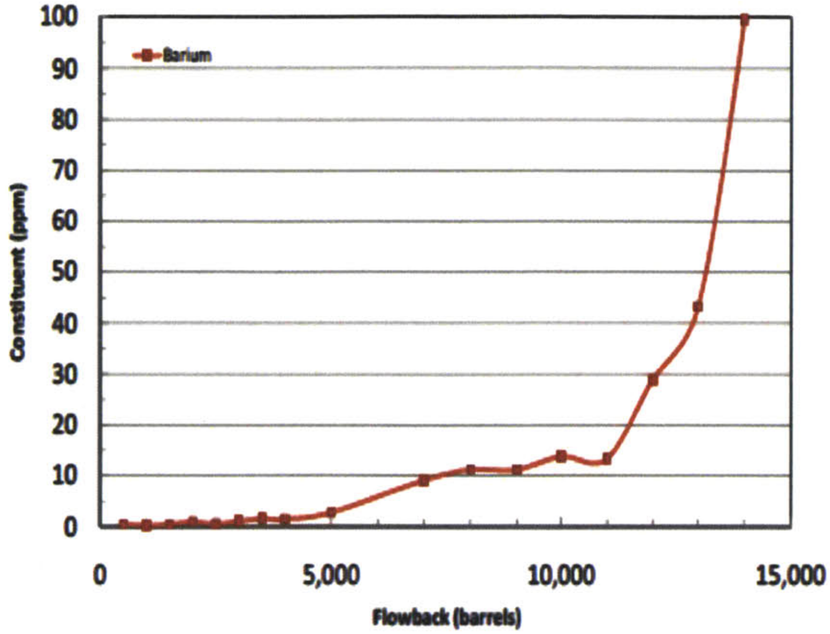

Figure E.4 – Marcellus shale well; A flowback analysis – barium trend (Blauch et al., 2009)

Appendix F – Wastewater Treatment Pathways

As discussed throughout this document, there are three main options to managing wastewater from shale gas operations:

A) Injection in disposal wells

B) Reuse in hydraulic fracturing operations

C) Surface discharge or beneficial use after treatment

The outputs from primary, secondary and tertiary treatment, shown in Figure 22, as well as the untreated produced water, can be managed in one of the three management options mentioned above. All the possible water management pathways between the three treatment and the three management options were analyzed and are listed in Table F.1. The process for every possible water management pathway is outlined in steps. Orange indicates that there is low to minimal likehood of water management pathways followed in industry. Yellow indicates that there is moderate possibility for that process to take place. Lastly, the six most likely water management pathways are identified in green and discussed in detail throughout Chapter 6 of this document.

Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7	Reason for high, medium, low likelihood of occuring
Untreated FB	Disposal						Injection well
Untreated FB	Reuse						Highly unlikely in the Marcellus
Untreated FB	Blending	Reuse					Extensively done in the Marcellus
Untreated FB	Blending	Tertiary Treatment	Reuse				Possible to blend before treatment
Untreated FB	Blending	Tertiary Treatment	< 500ppm				CWT will have pre-treatment
Untreated FB	Blending	Tertiary Treatment	Blending	Reuse			Unlikely to need blending after desal (blending would be before desal so that tech with lower TDS limit can be used)
Untreated FB	Tertiary Treatment	Reuse					Unlikely to send water to desal with no pre-treatment - catastrophic for membranes
Untreated FB	Tertiary Treatment	< 500ppm					Unlikely to send water to desal with no pre-treatment - catastrophic for membranes
Untreated FB	Tertiary Treatment	Blending	Reuse				Unlikely to send water to desal with no pre-treatment - catastrophic for membranes
Untreated FB	Primary Treatment	Disposal					Unlikely to invest in treatment and then send to disposal
Untreated FB	Primary Treatment	Reuse					Unlikely to reuse wastewater without reducing TDS and hardness
Untreated FB	Primary Treatment	Blending	Reuse				Extensively done in the Marcellus
Untreated FB	Primary Treatment	Blending	Tertiary Treatment	Reuse			Possible to blend before treatment
Untreated FB	Primary Treatment	Blending	Tertiary Treatment	< 500ppm			Possible to blend before treatment
Untreated FB	Primary Treatment	Blending	Tertiary Treatment	Blending	Reuse		Unlikely to need blending after desal (blending would be before desal so that tech with lower TDS limit can be used)
Untreated FB	Primary Treatment	Tertiary Treatment	Reuse				High likelihood of fouling
Untreated FB	Primary Treatment	Tertiary Treatment	< 500ppm				High likelihood of fouling
Untreated FB	Primary Treatment	Tertiary Treatment	Blending	Reuse			High likelihood of fouling
Untreated FB	Primary Treatment	Secondary Treatment	Disposal				Unlikely to invest in treatment and then send to disposal
Untreated FB	Primary Treatment	Secondary Treatment	Reuse				TDS would be too high
Untreated FB	Primary Treatment	Secondary Treatment	Blending	Reuse			Possible if hardness is too high
Untreated FB	Primary Treatment	Secondary Treatment	Blending	Tertiary Treatment	Reuse		If blending will take place, it would probably happen without secondary treatment
Untreated FB	Primary Treatment	Secondary Treatment	Blending	Tertiary Treatment	< 500ppm		If blending will take place, it would probably happen without secondary treatment
Untreated FB	Primary Treatment	Secondary Treatment	Blending	Tertiary Treatment	Blending	Reuse	Unlikely to need blending after desal (blending would be before desal so that tech with lower TDS limit can be used)
Untreated FB	Primary Treatment	Secondary Treatment	Tertiary Treatment	< 500ppm			CWT for discharge
Untreated FB	Primary Treatment	Secondary Treatment	Tertiary Treatment	Disposal			Unlikely to invest in treatment and then send to disposal
Untreated FB	Primary Treatment	Secondary Treatment	Tertiary Treatment	Blending	Reuse		Unlikely to need blending after desal (blending would be before desal so that tech with lower TDS limit can be used)
Untreated FB	Primary Treatment	Secondary Treatment	Tertiary Treatment	Reuse			Done currently by Aqua-pure (NOMAD), Aquatech etc.

Table F.1 - All possible wastewater treatment pathways based on Figure 25
Orange = Unlikely to occur; Yellow = Moderate possibility of occurring; Green = Likely to occur / Currently used;

Appendix G – DOE Water Mixing and Scale Affinity Model

(DOE & ALL Consulting, 2012)

The Department of Energy (DOE) Water Mixing and Scale Affinity Model was used to determine the make-up water requirements for blending. The composition of a typical Marcellus flowback stream, shown in Figure G.1, was used to determine the blending requirements. The limits for fracturing water reuse were determined based on the analysis in Section 4.3. Both scenarios of sourcing water from a municipal water supply and a lake withdrawal were considered. The results of how much make-up water is required for blending in order to meet re-fracturing or other criteria are shown in Table G.1.

Untreated flowback blended for reuse	Fresh water used	85%	Limits for water reuse
	TDS	20,510 ppm	TDS < 50000ppm
	Chlorides	13,839 ppm	Cl < 26000ppm
Untreated flowback blended for reuse	Lake water used	85%	Limits for water reuse
	TDS	21,954 ppm	TDS < 50000ppm
	Chlorides	13,755 ppm	Cl < 26000ppm

Flowback blended for reuse after primary and secondary treatment	Fresh water used	65%	Limits for water reuse
	TDS	45,330 ppm	TDS < 50000ppm
	Chlorides	25,314 ppm	Cl < 26000ppm
Flowback blended for reuse after primary and secondary treatment	Lake water used	70%	Limits for water reuse
	TDS	33,158 ppm	TDS < 50000ppm
	Chlorides	22,705 ppm	Cl < 26000ppm

Flowback blended before tertiary treatment	Fresh water used	20%	Limits for distillation
	TDS	95,770 ppm	TDS < 100000ppm
	Chlorides	66,875 ppm	
Flowback blended before tertiary treatment	Lake water used	25%	Limits for distillation
	TDS	97,680 ppm	TDS < 100000ppm
	Chlorides	72,680 ppm	

Table G.1 – Blending requirements for three wastewater treatment pathways: (a) Blending and reuse; (b) Primary and Secondary treatment, blending and reuse; (c) Blending prior to tertiary treatment. Calculations were completed for make-up water from both fresh water supply (sourced from municipality supply) and lake withdrawals.

Version 1.00.000

Untreated Flowback Water

Scale Calculations

Scale Calculations Results

Index Name	Index Result	Index Descriptions
Langelier Saturation Index	3.1356	Water tends to precipitate a scale layer of CaCO3.
Stiff-Davis Stability Index	2.5314	Water tends to precipitate a scale layer of CaCO3.
Oddo-Tomson Scale Index	3.8983	Water tends to precipitate a scale layer of CaCO3.
Ryznar Stability Index	0.1289	Heavy scale will form (Ryznar 1942).
Puckorious Scaling Index	-4.6435	Heavy scale will form.
Larson-Skold Index	6.2758	Dissolution of minerals may occur if available. (High rates of localized corrosion may be expected.)
Skillman Index	0.1353	Fixed at a Gypsum Ksp value for 25 C. Dissolve mineral.
Driving Force Index	1,903.0374	Scales form.
Aggressive Index	15.3333	Scales form.

Water Property

Phase	Value	Units
pe	0	
pH	6.4	
temp	25	C
Alkalinity as CaCO3	33669	ppm
Ba	3100	ppm
Ca	10200	ppm
Cl	79000	ppm
Fe	34.9	ppm
K	425	ppm
Mg	901	ppm
Na	30500	ppm
S(6)	1.6	ppm
Sr	1930	ppm
TDS	124303	ppm

Figure G.1 – Composition of typical Marcellus shale flowback water

Version 1.00.000

Flowback water after primary and secondary treatment

Scale Calculations

Scale Calculations Results

Index Name	Index Result	Index Descriptions
Langelier Saturation Index	0.6997	Water tends to precipitate a scale layer of CaCO3.
Stiff-Davis Stability Index	-0.1628	Water is in equilibrium with CaCO3. A scale layer of CaCO3 is neither precipitated nor dissolved.
Oddo-Tomson Scale Index	1.7096	Water tends to precipitate a scale layer of CaCO3.
Ryznar Stability Index	6.1005	Scale will form (Ryznar 1942). Little scale or corrosion (Carrier 1965).
Puckorious Scaling Index	4.2245	Heavy scale will form.
Larson-Skold Index	59.8043	Dissolution of minerals may occur if available. (High rates of localized corrosion may be expected.)
Skillman Index	0.0033	Fixed at a Gypsum Ksp value for 25 C. Dissolve mineral.
Driving Force Index	12.3240	Scales form.
Aggressive Index	12.8975	Scales form.

Water Property

Phase	Value	Units
pe	0	
pH	7.5	
temp	25	C
Alkalinity as CaCO3	2000	ppm
Ba	50	ppm
Ca	50	ppm
Cl	79000	ppm
Fe	5	ppm
K	425	ppm
Mg	25	ppm
Na	30500	ppm
S(6)	1.6	ppm
Sr	50	ppm
TDS	124303	ppm

Figure G.2 – Composition of Marcellus flowback water after primary and secondary treatment

Version 1.00.000

Treated water for frac reuse after desalination

Scale Calculations

Scale Calculations Results

Index Name	Index Result	Index Descriptions
Langelier Saturation Index	0.7791	Water tends to precipitate a scale layer of CaCO3.
Stiff-Davis Stability Index	-0.0620	Water is in equilibrium with CaCO3. A scale layer of CaCO3 is neither precipitated nor dissolved.
Oddo-Tomson Scale Index	1.7096	Water tends to precipitate a scale layer of CaCO3.
Ryznar Stability Index	5.9418	Scale will form (Ryznar 1942). Light scale (Carrier 1965).
Puckorious Scaling Index	4.0658	Heavy scale will form.
Larson-Skold Index	9.4635	Dissolution of minerals may occur if available. (High rates of localized corrosion may be expected.)
Skillman Index	0.0033	Fixed at a Gypsum Ksp value for 25 C. Dissolve mineral.
Driving Force Index	12.3240	Scales form.
Aggressive Index	12.8975	Scales form.

Water Property

Phase	Value	Units
pe	0	
pH	7.5	
temp	25	C
Alkalinity as CaCO3	2000	ppm
Ba	50	ppm
Ca	50	ppm
Cl	12500	ppm
Fe	5	ppm
K	425	ppm
Mg	25	ppm
Na	20000	ppm
S(6)	1.6	ppm
Sr	50	ppm
TDS	20000	ppm

Figure G.3 – Composition of Marcellus flowback water after tertiary treatment. Water is ready for reuse in fracturing operations

Below is a sample of the blending analysis. The two fluids used in this particular run are (a) high TDS untreated flowback (15% by volume) (Figure G.1) and (b) fresh municipal water (85% by volume). The top figure shows the resulting water composition after mixing. The bottom figure indicates the resulting TDS at various levels of mixing.

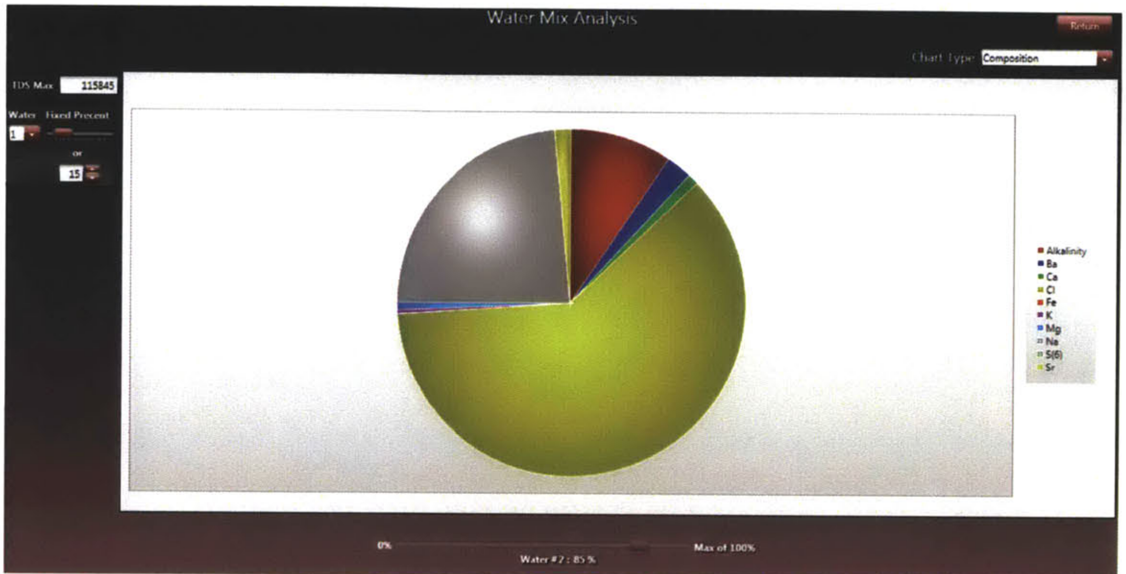

Figure G.4 – Resulting composition of blended water (15% high TDS untreated flowback water (Figure G.1) – 85% fresh municipal water)

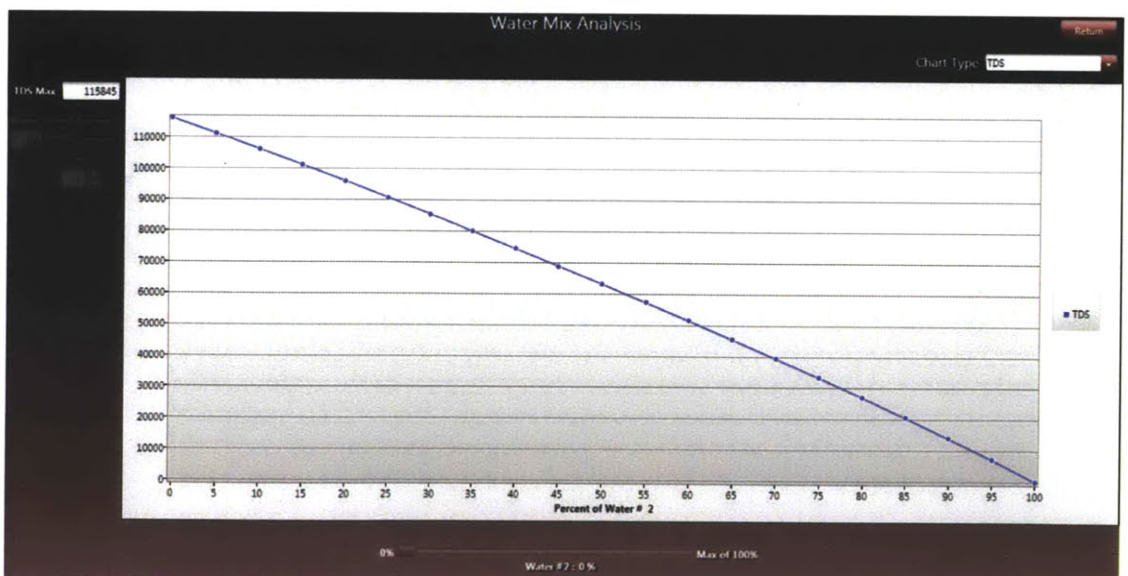

Figure G.5 – Resulting TDS concentration at various levels of mixing with Water #2. Water #1 = high TDS untreated flowback water (Figure G.1); Water #2 = fresh municipal water.

Appendix H – Location of natural gas and disposal wells

Distances between natural gas well sites and disposal wells can play a determining factor on choosing a water management method.

Figure H-1 shows the location of all the Marcellus wells drilled during January to July 2011. Figure H-2 indicates the location of all the brine disposal wells in Ohio.

There are two well defined clusters of natural gas wells, one located on the northeast part of Pennsylvania and the other on the southwest part. The information necessary from these maps are the maximum and minimum distances between these clusters of natural gas wells and the disposal wells. The tables below identify locations that are indicative of the minimum and maximum distances between wells sites and disposal wells.

Northeast natural gas wells cluster:

	Well sites in Wyoming, PA (NE, PA)	Well sites in Susquehanna, PA (NE, PA)
Disposal wells in Trumbull, OH	300 miles	340 miles
Disposal wells in Athens, OH	465 miles	520 miles
Disposal wells in Morrow, OH	535 miles	590 miles

Table H.1 – Minimum and maximum distances between wells sites located in the northeast part of PA and three main disposal well locations in Ohio

Southwest and Central natural gas wells cluster:

	Well sites in Washington, PA (SW, PA)	Well sites in Clearfield, PA (Central, PA)
Disposal wells in Trumbull, OH	100 miles	140 miles
Disposal wells in Athens, OH	150 miles	310 miles
Disposal wells in Morrow, OH	230 miles	380 miles

Table H.2 – Minimum and maximum distances between wells sites located in the southwest and central part of PA and three main disposal well locations in Ohio

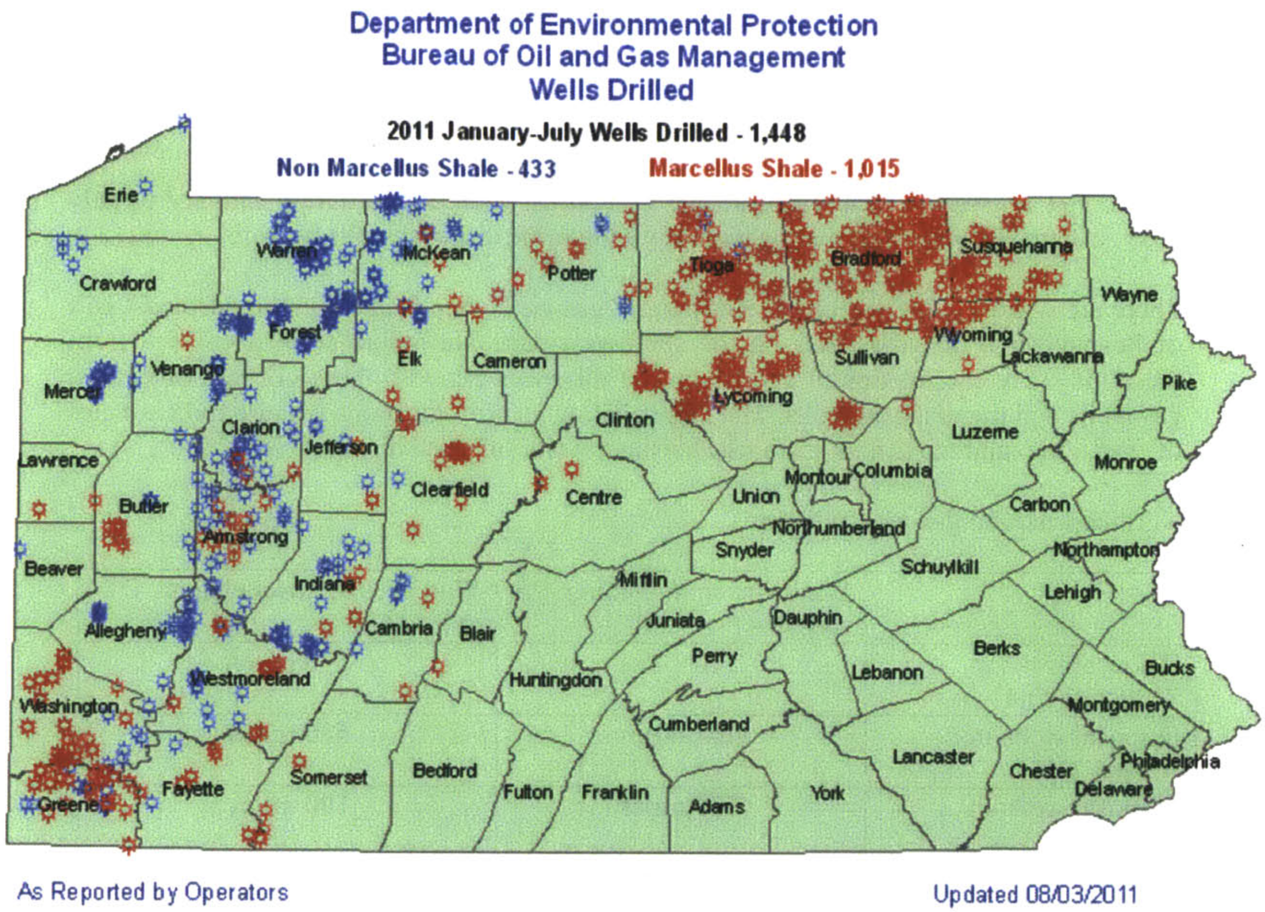

Figure H.1 – Wells drilled in Pennsylvania during January – July 2011 (PA DEP, 2011b)

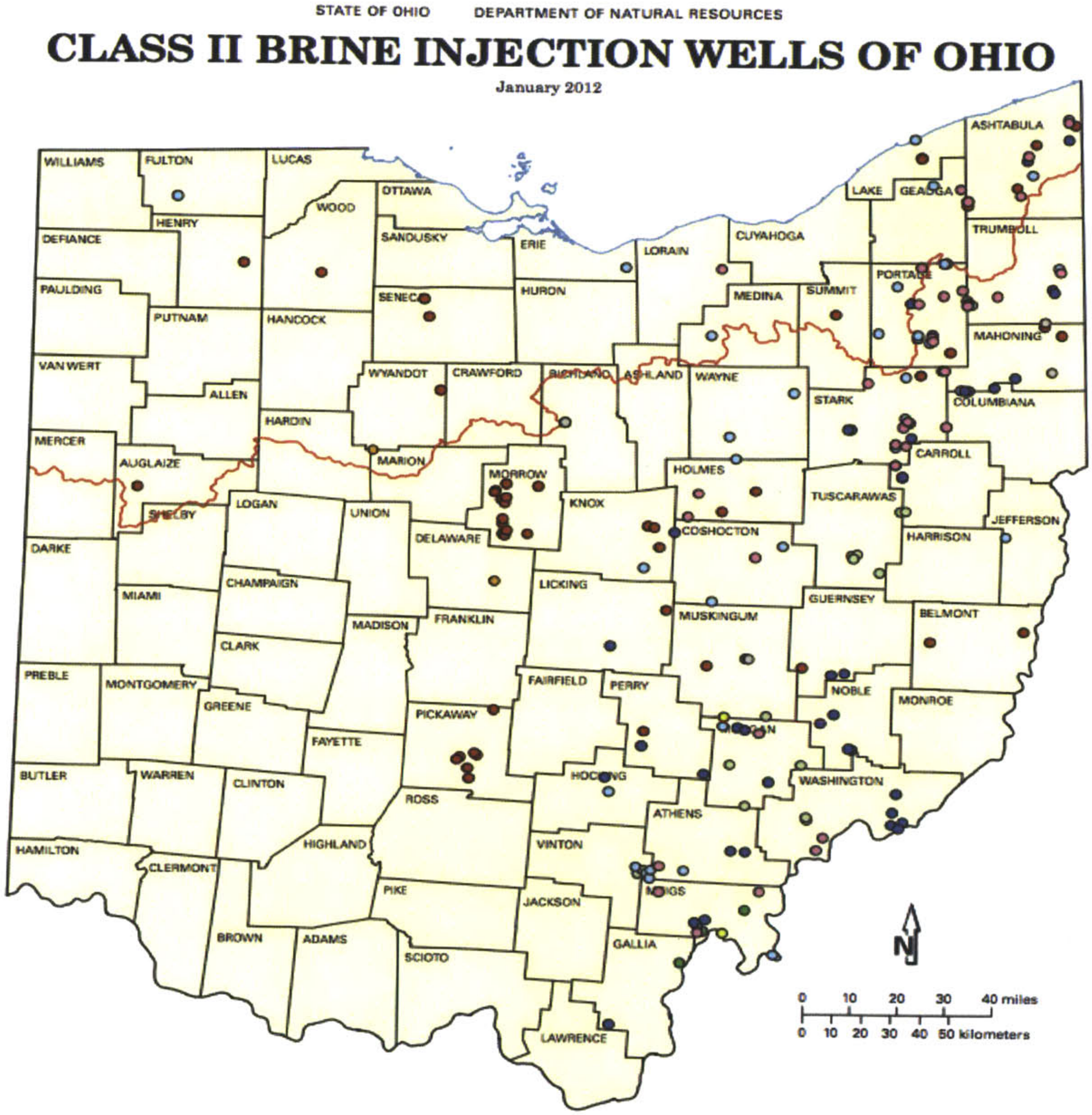

Figure H.2 – Class II Disposal Wells in Ohio as of January 2012 (DNR, 2012)

Appendix I – GAMS Code for Mixed Integer Linear Programming

Two-period model

In this particular formulation the model includes the assumptions stated in Tables 33 and 34. The output of this particular run is shown in Table 35.

```
$Title  A Water Management Problem (TRNSPORT,SEQ=1)
$Ontext

This problem finds a minimum cost technology schedule that meets
water treatment requirements for flowback and produced water.

$Offtext

  Sets
       i       technology     / injection, cwt, reuse /
       t       time           / 1*2 /
       i2(i)   selecttech     / injection /       ;

  Parameters

       V(t)   water to be treated
         /     1     20767
               2     62301    /

       time(t) time
         /     1     0
               2     1        /
                                     ;

  Table cap(i,t)  total capacity of each tech
                      1        2
      injection      200000   200000
      cwt            92850    92850
      reuse          10000    10000       ;

  Table captech (i,t)  unit capacity of each tech
                      1        2
      injection      1000     1000
      cwt            6190     6190
      reuse          100      100       ;

  Table FC(i,t)  fixed cost of each tech
                      1         2
      injection      2000000   2000000
      cwt            15000000 15000000
      reuse          750000    750000     ;

  Table VC(i,t)  variable cost of each tech
                      1        2
      injection      6.4      6.4
      cwt            7.4      7.4
      reuse          4.4      4.4       ;

  Scalar g  penalty  /25000/ ;
```

```
Scalar dr discount rate  /0.10/ ;

Variables

     x(i,t)       volume per tech
     nnew(i,t)    units of tech
     TC           total cost ;

Positive Variable x(i,t) ;

Integer Variable nnew(i,t) ;

Equations
     cost                define objective function
     water(t)            don't treat more than enough water
     capacitycheck(i,t)
     captechlimit(i,t)   tech capacity never exceeds total cap limit
          ;

cost ..
TC=e=sum((t,i),(VC(i,t)*x(i,t)+FC(i,t)*nnew(i,t))*(1/(power((1+dr),time
(t)))))+g*(sum(t,(V(t)-sum(i,x(i,t)))*(1/(power((1+dr),time(t))))));

water(t) ..            sum(i, x(i,t))  =l=  V(t) ;

capacitycheck(i,t)..   x(i,t) =l= cap(i,t) ;

captechlimit(i,t)..    nnew(i,t)*captech(i,t)  =g=  x(i,t)-x(i,t-1) ;


Model watermodel /all/ ;

Solve watermodel using mip minimizing TC ;

Display x.l, nnew.l, TC.l ;
```

Five-period model

In this particular formulation the model includes the assumptions stated in Table 38 (increasing drilling rates case) and Table 34. One adjustment to the Table 34 assumptions is that the avaible units for injection are reduced to 50 after t=4. The output of this particular run is shown in Table 39.

```
$Title  A Transportation Problem (TRNSPORT,SEQ=1)
$Ontext

This problem finds a least cost shipping schedule that meets
requirements at markets and supplies at factories.

$Offtext

*comment can be written with a star

  Sets
     i       technology    / injection, cwt, reuse /
     t       time          / 1*5 /
     i2(i)   selecttech    / injection /      ;

  Parameters

     V(t)   water to be treated
       /     1     23797
             2     66063
             3     89000
             4     115000
             5     142500
                             /

     time(t) time
       /     1    0
             2    1
             3    2
             4    3
             5    4            /
                                ;

  Table cap(i,t)  total capacity of each tech
                    1       2       3       4         5
    injection      200000  200000  200000  50000     50000
    cwt            92850   92850   92850   92850     92850
    reuse          10000   10000   10000   10000     10000   ;

  Table captech(i,t)  unit capacity of each tech
                    1     2     3     4      5
    injection      1000  1000  1000  1000   1000
    cwt            6190  6190  6190  6190   6190
    reuse          100   100   100   100    100   ;

  Table FC(i,t)  fixed cost of each tech
                    1        2          3        4        5
    injection      2000000  2000000   2000000  2000000  2000000
    cwt            15000000 15000000  15000000 15000000 15000000
    reuse          750000   750000    750000   750000   750000   ;
```

```
Table VC(i,t)  variable cost of each tech
                 1        2       3        4        5
    injection    6.4      6.4     6.4      6.4      6.4
    cwt          7.4      7.4     7.4      7.4      7.4
    reuse        4.4      4.4     4.4      4.4      4.4      ;

Scalar g  penalty  /25000/ ;
Scalar dr discount rate  /0.10/ ;

Variables
     x(i,t)       volume per tech
     nnew(i,t)    units of tech
     TC           total cost ;

Positive Variable x(i,t) ;

Integer Variable nnew(i,t) ;

Equations
     cost                     define objective function
     water(t)                 don't treat more than enough water
     capacitycheck(i,t)
     captechlimit(i,t)        tech capacity never exceeds total cap
limit  ;


  cost ..
TC =e= sum
((t,i),(VC(i,t)*x(i,t)+FC(i,t)*nnew(i,t))*(1/(power((1+dr),time(t)))) )
+ g*(sum(t,(V(t)-sum(i,x(i,t)))*(1/(power((1+dr),time(t))))) ) ;

  water(t) ..            sum(i, x(i,t))  =l=  V(t) ;
* =l= means less than

  capacitycheck(i,t)..    x(i,t) =l= cap(i,t) ;

  captechlimit(i,         nnew(i,t)*captech(i,t)  =g=  x(i,t)-x(i,t-1);


  Model watermodel /all/ ;

  Solve watermodel using mip minimizing TC ;

  Display x.l, nnew.l, TC.l ;
```